EPRI

Hydro Life Extension Modernization Guide

Volume 3: Electromechanical Equipment

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Hydro Life Extension Modernization Guide

Volume 3: Electromechanical Equipment

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REPORT SUMMARY

Hydroelectric power generation is a proven vital source of electricity in the United States and worldwide. This guideline represents the third in a series of seven to help hydroelectric utilities assess the needs and benefits of life extension and modernization. This volume focuses on alternatives for plant electromechanical equipment to assist in evaluating the cost and economic justification for various alternatives and to implement the selected plan. It also provides a screening procedure and criteria to enable utility personnel to identify which hydroelectric plants may be suitable for modernization and which plants promise the most immediate return on investment.

Background

Volume 3: Electromechanical Equipment is the third in a series of guidelines for assessing the needs and benefits and evaluating the cost and economic justification of life extension and modernization (LEM) alternatives. It covers the plant electromechanical equipment, particularly the generator. It also provides a screening procedure and criteria to enable utility personnel to identify opportunities for modernization of plant electromechanical equipment.

Hydroelectric power generation is a proven vital source of electricity in the United States and throughout the world. Many hydroelectric plants have been reliably generating electricity for more than 50 years. Because these facilities continue to age, decisions must be made concerning retirement, continued maintenance and operation, or modernization and redevelopment. Experienced personnel retire and leave utility companies, and so the need for guidance in making these critical decisions becomes even more important.

There is a crucial need for guidance in helping utility managers and owners make critical decisions regarding the future of their plants. In 1989, EPRI issued three volumes of modernization guidelines that have been widely used by the industry. This series of guidelines updates the 1989 guides and expands them to cover the entire plant.

Objectives

- To provide technical information and data on the plant electromechanical equipment, particularly the generator, that can be used as input for the LEM of hydropower plants anywhere in the world
- To compile information on available and developing technology
- To develop guidelines to assess needs for LEM and develop a cost-effective life cycle plan
- To provide technical data and information required for implementation
- To identify license implications of any upgrades

- To identify improvements that can decrease environmental impacts
- To produce a resource tool for experienced and novice utility engineers

Approach

The information supplied is the result of an extensive search and review of literature on hydroelectric plant electromechanical equipment, particularly the generator and its associated equipment.

Results

This volume of *Hydro Life Extension Modernization Guides* provides technical information for the LEM planning process described in Volume 1 and guides the user in establishing a base case, pinpointing high-value alternatives, and incorporating them into the overall LEM plan. Guidance on selection and procurement of equipment and services as well as implementation of the LEM plan is also provided. Throughout the process, the focus is on creating value by applying technologies that offer the greatest return. This requires an understanding of the technologies and their applications as well as an awareness of markets and the need to match technology to market demand.

EPRI Perspective

Deregulation and the privatization of the electricity industry around the globe present threats but also opportunities. As energy markets develop, demands must be met instantaneously and reliably, and hydro assets will increase in value. A comprehensive set of guidelines for the LEM of hydro plants can help to ensure that plants have the equipment and processes they need to supply electricity to the modern world, therefore ensuring hydro's ability to capture its deserved market share.

Keywords

Asset management
Electromechanical equipment
Generators
Hydroelectric
Life extension
Modernization

ABSTRACT

Under contract to EPRI, BC Hydro is developing a seven-volume set entitled *Hydro Life Extension Modernization Guides*. These documents, superseding the three-volume 1989 guides published by EPRI, will enable utility personnel to identify the hydroelectric plants that are potentially suitable for modernization because they promise the most immediate return on investment. They will also provide guidance on the design and implementation of the selected plan. Volume 3 covers the electromechanical plant, particularly the generator and its associated equipment.

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A number of individuals provided information and contributed to the production of this report. Valuable input and comments were received from representatives of the project team including BC Hydro Ltd. and Acres International Ltd. EPRI staff reviewed this document.

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1
INTRODUCTION AND SCOPE

1.1 Volumes 1–7

Volume 1 of *Hydro Life Extension Modernization Guides*, referred to subsequently as Volume 1, addresses how to formulate an integrated plan for an entire plant. It does not cover the technical specifics for each plant area, but it requires that detailed technical information be acquired.

Volumes 2–7 of these guidelines provide the detailed information required to successfully use Volume 1. The subject matter of Volumes 2–7 is:

- Volume 2: Hydromechanical equipment
- Volume 3: Electromechanical equipment
- Volume 4: Auxiliary mechanical systems
- Volume 5: Auxiliary electrical systems
- Volume 6: Civil and other plant components
- Volume 7: Protection, control, and automation

1.2 Volume 3: Electromechanical Equipment

The electromechanical aspects of the plant are the generator and its associated components. For this report, the systems are:

- Stator (armature)
- Rotor (field)
- Generator guide and thrust bearings
- Excitation system
- Terminal equipment
- Unit circuit breaker
- Cables and buses
- Generator fire protection
- Braking system
- Cooling

Volume 3 updates the electromechanical information in GS-6419, *Hydropower Plant Modernization Guide,* 1989.

The generator is a primary candidate for modernization to improve unit performance and reliability and, in some cases, reduce costs. The generator is a significant component for modernization consideration, based on both cost and upgrade potential. Modern generators have significant advantages over older generators in specific power density, efficiency, and dependability.

The effect of generator modernization on the overall plant is a critical aspect of any improvement plan and is addressed in Chapter 5.7.

1.3 Purpose of Volume 3

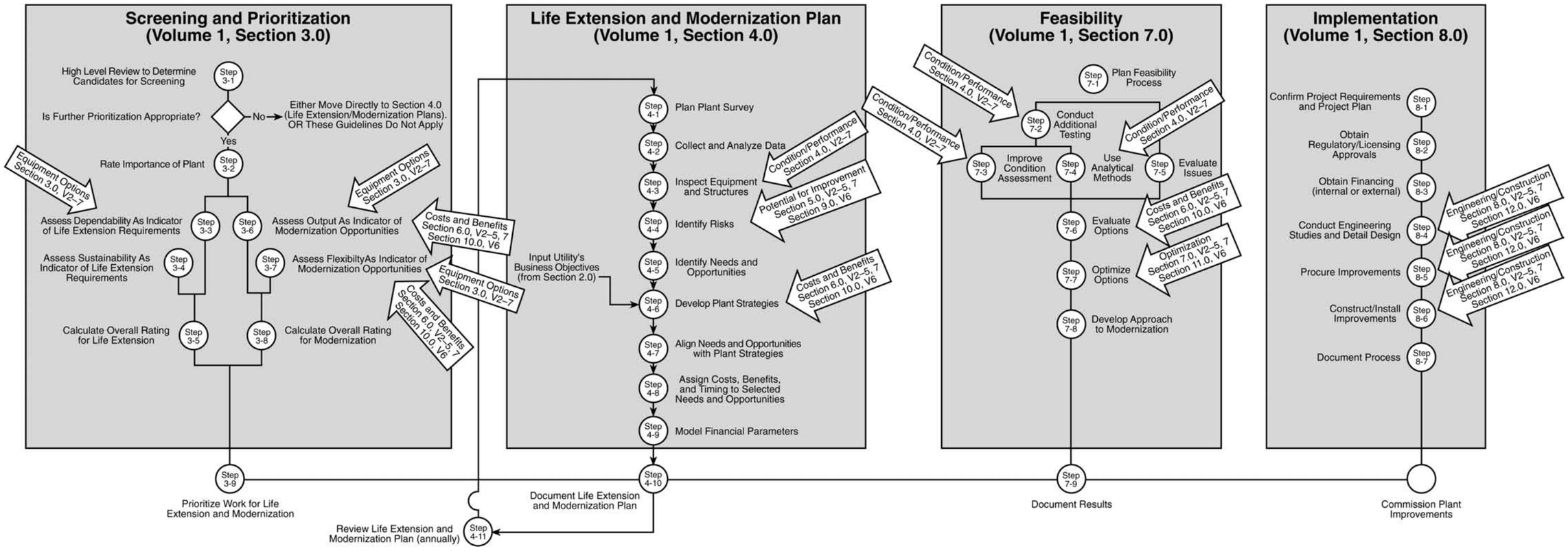
Volume 1 describes the overall process for developing a life extension and modernization (LEM) plan for a plant. Technical information is required for most of the steps in the process so that the needs (life extension requirements) and opportunities (modernization possibilities) of the plant can be clearly defined and addressed in terms of actual activities or plant projects.

Volume 3 describes technical information and data on electromechanical equipment that can be used as input to the LEM planning process as developed through Volume 1. Volume 3 is used after the screening of facilities and the selection of plants suitable for LEM studies are completed as described in Volume 1, Chapter 3. Volume 3 is a technical resource to assist engineers and planners with the development of the LEM plan for a particular plant or units. Volume 3 also assists in the design of projects for implementation.

Volume 3 can also be used as a stand-alone document for the condition assessment and review of the rehabilitation/upgrade options for generator equipment, outside of the overall development of a plant LEM plan.

1.4 How to Use Volume 3

Figure 1-1 shows how the various chapters of Volume 3 provide information to support the development of the LEM plan. This flowchart should be referred to on an ongoing basis, because the user works through the condition assessment and other technical aspects of Volume 3 to ensure that all necessary information is fed back into the Volume 1 process. The flowchart is adapted from the flowchart in Figure 1-2 of Volume 1 of these guidelines. Equipment information obtained in the plant screening process of Volume 1 should be used in Chapter 4, “Performance Evaluation and Condition Assessment” of Volume 3.


Screening and Prioritization
(Volume 1, Section 3.0)
High Level Review to Determine Candidates for Screening
Step 3-1
Is Further Prioritization Appropriate?
No
Either Move Directly to Section 4.0 (Life Extension/Modernization Plans). OR These Guidelines Do Not Apply
Yes
Rate Importance of Plant
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Collect and Analyze Data
Step 4-3
Inspect Equipment and Structures
Step 4-4
Identify Risks
Step 4-5
Identify Needs and Opportunities
Step 4-6
Develop Plant Strategies
Step 4-7
Align Needs and Opportunities with Plant Strategies
Step 4-8
Assign Costs, Benefits, and Timing to Selected Needs and Opportunities
Step 4-9
Model Financial Parameters
Condition/Performance Section 4.0, V2–7
Condition/Performance Section 4.0, V2–7
Potential for Improvement Section 5.0, V2–5, 7 Section 9.0, V6
Costs and Benefits Section 6.0, V2–5, 7 Section 10.0, V6
Step 4-10
Document Life Extension and Modernization Plan
Step 4-11
Review Life Extension and Modernization Plan (annually)
Feasibility
(Volume 1, Section 7.0)
Condition/Performance Section 4.0, V2–7
Condition/Performance Section 4.0, V2–7
Step 7-1
Plan Feasibility Process
Step 7-2
Conduct Additional Testing
Step 7-3
Improve Condition Assessment
Step 7-4
Use Analytical Methods
Step 7-5
Evaluate Issues
Costs and Benefits Section 6.0, V2–5, 7 Section 10.0, V6
Step 7-6
Evaluate Options
Optimization Section 7.0, V2–5, 7 Section 11.0, V6
Step 7-7
Optimize Options
Step 7-8
Develop Approach to Modernization
Step 7-9
Document Results
Implementation
(Volume 1, Section 8.0)
Confirm Project Requirements and Project Plan
Step 8-1
Obtain Regulatory/Licensing Approvals
Step 8-2
Obtain Financing (internal or external)
Step 8-3
Conduct Engineering Studies and Detail Design
Step 8-4
Procure Improvements
Step 8-5
Construct/Install Improvements
Step 8-6
Document Process
Step 8-7
Engineering/Construction Section 8.0, V2–5, 7 Section 12.0, V6
Engineering/Construction Section 8.0, V2–5, 7 Section 12.0, V6
Engineering/Construction Section 8.0, V2–5, 7 Section 12.0, V6
Commission Plant Improvements

Figure 1-1
Life Extension and Modernization Flowchart

Volume 3 provides a step-by-step process to identify and define projects that either extend equipment service life (life extension) or upgrade the equipment (modernization) in terms of performance. The general steps of the process are screening, evaluation of condition and performance, evaluation of "upgradability" and modernization potential, estimation of costs and benefits, and feasibility studies and implementation.

Volume 3 includes the following chapters that support these steps:

Chapter 1, "Introduction" - The needs, concepts, objectives, and scope of Volume 3 are explained. The user will gain an understanding of the content of the volume and whether or not it will be applicable to the user's needs, and how to use these guidelines.

Chapter 2, "Background to Life Extension and Modernization" - This chapter describes a utility's approach to LEM, including the policies and principles that should be in place.

Chapter 3, "Screening" - In this first step of the LEM process, the user obtains the necessary information about the electromechanical aspects of the unit. In many cases this information will justify proceeding directly to Chapter 4 and undertaking a detailed evaluation of condition and performance. Where it is uncertain, the user is led through the necessary steps of a desktop study to screen and prioritize the electromechanical aspects of the plant in terms of most likely to yield benefit from LEM.

Chapter 4, "Performance Evaluation and Condition Assessment" - This chapter focuses on a detailed assessment of the present performance and condition of the electromechanical components of the plant. This assessment is compared to the original design parameters of the plant to determine the scope of life extension activities and provides a base for consideration of modernization.

Chapter 5, "Modernization: Potential for Improvements" - This chapter covers the modernization opportunities available for electromechanical equipment and their assessment.

Chapter 6, "Estimate of Costs and Benefits" - Cost-estimating information is detailed, and the benefits, power and non-power, of LEM activities are presented.

Chapter 7, "Feasibility: Optimization of Alternatives" - This chapter covers the detailed investigative activities of the feasibility stage of the LEM process. Based on an iterative approach to developing the LEM plan, some projects (particularly modernization projects) will require a detailed feasibility study to determine their technical feasibility and economic worth. Most of the life extension projects, which only restore equipment to its original condition and level of service, will not require a detailed feasibility study. In some cases, a simple evaluation of the cost of rehabilitation versus replacement may be all that is warranted. Projects that have an impact on overall plant operation or other plant equipment will require more detailed evaluation and optimization of alternative project scenarios.

Chapter 8, "Implementation of Modernization Plan" - This step of the LEM process addresses those activities required to implement the selected LEM plan and the details required from the electromechanical perspective to successfully complete the project.

Chapter 9, "References" – A listing of references is included in this chapter.

Appendix A, "Literature Review" - An annotated bibliography of case histories, reports of new technologies and processes, and other published papers for further reading are presented.

Appendix B, "Procurement Guides" - Sample technical specifications for the purchase of stator cores and stator windings and the rehabilitation of a generator are described.

Appendix C, "Electrical Equipment Suppliers" - This chapter provides information about suppliers of generator components.

Appendix D, "Repair, Evaluation, Maintenance, and Rehabilitation Condition Assessment Procedures" – The U.S. Army Corps of Engineers (USACE) "Condition Rating Procedures/Condition Indicator for Hydropower Equipment" chapters pertaining to electromechanical equipment are reproduced. This document is part of the USACE's Repair, Evaluation, Maintenance, and Rehabilitation (REMR) research program.

1.5 Definitions

In the hydropower industry, the terms "life extension," "rehabilitation," "modernization," "upgrade," "upgrading," and "uprating" are used to indicate the nature, extent, or result of an improvement to a hydro plant or component. These terms are frequently used interchangeably. For this report, the following are the "improvement" terms that are used:

Life Extension is defined as the replacement or improvement of components that have been the cause of higher maintenance repair, or for which failure, due to age, is expected in the foreseeable future. Other terms that are close in meaning and often used interchangeably with life extension include rehabilitation, retrofit, replacement, and refurbishment. The term *overhaul* has a slightly different meaning and usually refers to the planned disassembly, cleaning, repair, lubrication, and re-assembly of a unit or component.

Modernization is defined as the improvement of level of service and cost of service (refer to Volume 1, Chapter 2.3.1) measured by plant output and/or flexibility. Other terms that are close in meaning and often used interchangeably with modernization include upgrade, upgrading, and uprating.

Redevelopment is defined as new construction of an existing plant, including replacement or substantial modification of civil, mechanical, and electrical components. Redevelopment is not covered by these guidelines.

2
BACKGROUND TO LIFE EXTENSION AND MODERNIZATION

2.1 Introduction

Volume 3 describes the main electromechanical equipment in a hydro plant. Auxiliary electrical equipment, such as the step-up transformer, batteries, and station service, is covered in Volume 5, *Auxiliary Electrical Systems* of these guidelines. Similarly, unit automation and protection and control are covered in Volume 7, *Protection, Control, and Automation*.

It is assumed that the user of the guidelines has a basic understanding of generators, exciters, and circuit breakers; therefore, descriptions of the equipment are not provided.

2.2 Objectives of Hydro Life Extension and Modernization

Each hydro life extension and/or modernization project has its own, sometimes unique, objectives. Among possible objectives for a specific project are:

- Plant life extension and restoration of original performance levels
  - To extend equipment life
  - To restore capacity
  - To halt or decelerate deterioration
  - To reduce forced outages or unscheduled down time
  - To reduce operating and/or maintenance costs
  - To reduce frequency of overhauls and scheduled downtime
  - To reduce undesirable operating characteristics
- Plant modernization to improve plant products and economics
  - To increase generating capacity
  - To improve efficiency
  - To improve ability to control equipment, for example, remote control and automation

  - To improve ability to deliver ancillary services such as voltage support, synchronous condensing capability, and black start
  - To improve plant/personnel safety
  - To avoid obsolescence problems such as lack of manufacturer support and unavailability of replacement parts
- Risk management and environmental compliance
  - To reduce risk of catastrophic failure
  - To reduce potential for environmental degradation
  - To enhance water quality
  - To reduce aquatic impacts
  - To meet legal/licensing requirements

2.3 Trends in Life Extension and Modernization

An industry benchmarking survey was conducted in conjunction with the HydroVision 98 conference. The survey, based on the 66 reported projects, provides a good sampling of general approaches and practices implemented by hydro owners, primarily in North America, with regard to plant or component LEM. Relevant information about each project is provided in TR-113584-V2, *Hydropower Technology Round-Up Report, Part 2: Rehabilitating and Upgrading Hydro*, 1998. The report presents statistics on the reasons for life extension and/or modernization, strategies employed, economic and prioritization criteria, contracting arrangements, and quality control and testing methods. Leading the list of project components approved for life extension and/or modernization are turbine runners and miscellaneous components, generator stator windings and miscellaneous components, excitation systems, and governors. The information in Table 2-1 is adapted from TR-113584-V2, *Hydropower Technology Round-Up Report, Part 2: Rehabilitating and Upgrading Hydro*, 1998, pages 5-9 to 5-15, and displays projects more specific to generator upgrading.

The survey report indicates that in nearly one-third of the projects reported, owners specified environmentally superior technology for new plant equipment. Respondents also reported that 18% of the projects accomplished a reduction of environmental risk.

Table 2-1
Generator Life Extension and Modernization Programs and Projects

Program, Project, or Powerhouse[1]	State (U.S.), Province (Canada), or Country	Owner	Scope of Program or Project	No. of Units	MW[2]	Status[3]	Cost $ million[4]
Hydro Modernization*	Tennessee and several adjacent states	Tennessee Valley Authority	Variously: runner replacement, other turbine modification, generator rewinding, other generator modification, control upgrades	88		in prog.	
Yale*	Washington	PacifiCorp	Runner replacement, other turbine modification, generator modification, controls upgrade	2	125	comp. 1996	
Great Falls*	South Carolina	Duke Power	Turbine replacement, generator modification, controls upgrade	2	6	comp. 1992	
Stechovice*	Czech Republic	Czech Power Company CEZ, a.s.	Pump-turbine and motor-generator replacement	1	42	comp. 1997	
Rocky Reach*	Washington	Chelan County PUD	Runner replacement, other turbine modification, generator modification, controls upgrade	11	1380	in prog.	116
Twin Branch*	Indiana	American Electric Power Corporation	Turbine and generator replacement	6	7.3	comp. 1992±	
Berrien Springs*	Michigan	American Electric Power Corporation	Turbine and generator replacement	4	7.2	comp. 1997±	
Shasta*	California	U.S. Bureau of Reclamation	Runner replacement, generator rewinding, other generator modification	3	328	in prog. 2002±	21
Amprior	Ontario	Ontario Hydro	Generator modification for stiffness	2	70	comp. 1993	
Lookout Shoals*	North Carolina	Duke Power	Replacement of turbine-driven exciter with generator	2	0	comp. 1996	
Major Rehabilitation	Many states	U.S. Army Corps of Engineers	Comprehensive rehabilitation, economic revaluation, stator iron replacement				450±
Porjus	Sweden	Vattenfall	High-voltage generator (prototype test)	1	11±	comp. 1998	

Table 2-1 (cont.)
Generator Life Extension and Modernization Programs and Projects

Program, Project, or Powerhouse[1]	State (U.S.), Province (Canada), or Country	Owner	Scope of Program or Project	No. of Units	MW[2]	Status[3]	Cost $ million[4]
Beauharnois*	Quebec	Hydro-Qu∂bec	Variously: runner replacement, generator rewinding, controls upgrade	38	1666	in prog. 2002±	Cdn1500
Nine Mile*	Washington	Washington Water Power	Turbine and generator replacement, controls upgrade	2	6.8	comp. 1995?	
Boundary	Washington	Seattle City Light	Comprehensive rehabilitation of entire plant	6	1051	in prog. 2008	88
Inks*	Texas	Lower Colorado River Authority	Runner replacement, generator rewinding, controls upgrade	1	11.4	comp. 1997	6.4
Buchanan*	Texas	Lower Colorado River Authority	Runner replacement, generator rewinding, controls upgrade	2	25	in prog. 1999	11.5
Austin*	Texas	Lower Colorado River Authority	Runner replacement, generator rewinding, controls upgrade	2	15.0	comp. 1994	10.4
B∂rfell*	Iceland	Landsvirkjun	Partnering, runner replacement, generator modification, controls upgrade	6	210	in prog.	

1. Asterisk (*) indicates program or project is listed in Table 2-3, Generator Capacity and Efficiency Improvements.

2. Capacity of units rehabilitated or upgraded (or planned to be rehabilitated or upgraded) prior to work; capacities are presented for comparison and may be nominal values.

3. Status noted as follows: in. prog. - in progress, year indicates expected completion date where known
comp. - completed; year indicates completion date where known.

4. Cost of program or project in US$ unless otherwise noted.

2.3.1 Gains in Capacity and Efficiency

Table 2-2 presents data about the significant improvements in capacities and efficiencies resulting from turbine and generator modernization, as described in the HydroVision 98 benchmarking survey report.

Table 2-2
Improvements from Turbine and Generator Modernization

	Percentage of Projects with Reported Increases	% Increase *Average*	% Increase *Range*
Turbine Capacity	42	23.8	1–230
Generator Capacity	29	20.1	1–67
Turbine Efficiency	22	6.1	3–15
Generator Efficiency	3	1.5	1–2

The benchmarking survey report also presents statistics on the reasons for modernization, strategies employed, economic and prioritization criteria, contracting arrangements, and quality control and testing methods.

Table 2-3 presents data about generator-related capacity and efficiency gains realized or expected as a result of the LEM programs and projects as described in the survey, and is adapted from TR-113584-V2, *Hydropower Technology Round-Up Report, Part 2: Rehabilitating and Upgrading Hydro*, 1998, pages 5-16 to 5-18. Additional information about the survey is also available in Volume 2 of these guides.

Table 2-3
Generator Capacity and Efficiency Improvements (In Order of Decreasing MW Capacity Prior to Upgrade)

Program or Project	Owner	No. of Units	Type of Units	Capacity Prior (MW)[1]	Capacity After (MW)[1]	Capacity Gain (MW)	Efficiency Gain[2]	Cost $ million[3]
Beauharnois	Hydro-Québec	27 11	Francis propeller	1666			13%[4]	Cdn1500
Rocky Reach	Public Utility District No. 1 of Chelan County	7 4	Kaplan propeller -> Kaplan	1280	1316	36		116
Hydro Modernization Completed to date: Total programs:	Tennessee Valley Authority	 23 77	Varies	700±	850±	152	5.7%	
Shasta	U.S. Bureau of Reclamation	3	Francis	328	426	98		21
Burfell	Landsvirkjun	6	Francis	230	300	70	4%	
Yale	PacifiCorp	2	Francis	100*	140*	9%		
Stechovice	Czech Power Company CEZ, a.s.	2	Pump-turbine	42	53/50[5]	8		
Austin	Lower Colorado River Authority	2	Kaplan	15.0	17.3	2.3		10.4
Inks	Lower Colorado River Authority	1	Francis	11.5	14.9	3.4		6.4
Berrien Springs	American Electric Power Corporation	4	Francis to semi-Kaplans	7.2	7.2	0		
Nine Mile	Washington Water Power	2	Francis quad-runner dbl. Draft	6.8	20	13.2	23%[4]	
Great Falls	Duke Power	2	Francis	6	8	2		
Lookout Shoals	Duke Power	2	Francis	0	0.8	0.8		

1. Capacity (MW) values do not necessarily represent official plant or unit ratings and should be considered “nominal." Capacity (MW) values given are known or understood to represent maximum output, except that values noted with an asterisk (*) are known to represent best efficiency output.
2. Nominal improvement in maximum (best gate) efficiency except as noted; see [4].
3. Cost of program or project in US$ unless otherwise noted.
4. Improvement in annual generation.
5. Pump input/turbine output.

2.4 Generator Capability Curve

Figure 2-1 illustrates a simplified capability curve for a typical hydroelectric generator. The goal of Volume 3 is the improvement of the economic performance of the generator by restoring or improving the capacity of the generator. Throughout the following chapters, the reader is advised to frequently refer to this simplified capability curve and to remain focused on the opportunity to increase real and/or reactive power output.

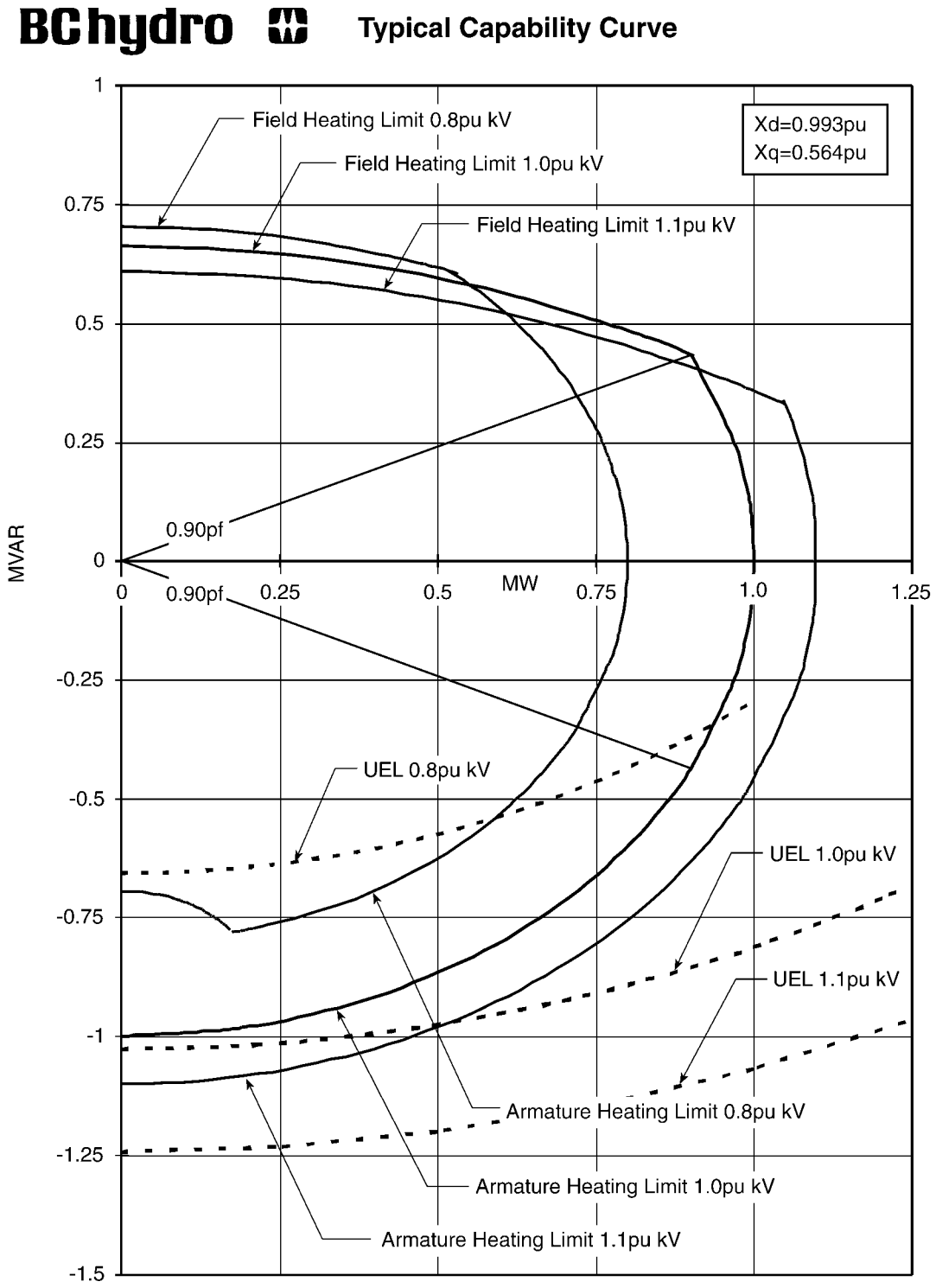

Figure 2-1
Typical Capability Curve

3
SCREENING

3.1 Introduction to the Screening Process

Proceeding with an electromechanical equipment screening process depends on prior or parallel steps. Equipment screening is recommended if the results of plant screening in Volume 1, Chapter 3 clearly indicate a need to proceed with a further detailed screening of unit equipment such as turbines (Volume 2, Chapter 3), protection and control (Volume 7, Chapter 3), or generators (Volume 3, Chapter 3). Equipment screening is also recommended if the hydro plant owner is considering an action plan driven by generator failure, derating, or unreliability. It may be desirable to complete a generator screening for the LEM plan regardless of other equipment condition, and the results may establish needs or opportunities that in turn suggest screening of other plant equipment.

The electromechanical equipment (generator) screening procedure is a quick and easy process used to evaluate whether life extension and/or modernization should be pursued. Through this process, the user can assess the potential for life extension and/or modernization of the generator, and the performance of detailed, costly studies of uneconomic alternatives can be avoided. A question and answer system is used, and special measurements or tests are not required.

The screening process for the generator uses the following indicators to assess whether modernization and/or life extension should be considered:

- Performance (capacity)
- Age
- Reliability
- Maintainability
- Operational opportunities (only applies to overall generator unit)

At this stage, rather than screen life extension and modernization separately, they are treated together. The method used here is to ask questions that may lead the user to Chapter 4 where a detailed assessment can be made and an approach to either life extension or modernization can be followed. A detailed description of the overall screening process for plant/units is in Volume 1, Chapter 3 of these guidelines.

The screening in Volume 3 complements that in Volume 1 but is at a greater level of detail. Screening is limited to the overall generator, the stator, the excitation system, the field windings, and generator bearings.

Screening

Indicators are a qualitative assessment based on a review of existing and easily obtainable information. They are provided to stimulate discussion and information gathering. The results of screening questions are summarized in Table 3-1 and then used as input to Step 3.3 of the screening process in Volume 1.

Table 3-1
Generation Equipment
Summary of Screening Indicators

Project: _____
Unit: _____
Asset Number:_____
Prepared by: _____
Date: _____

Is Generator life extension or modernization indicated in Generator Overall Screening (Chapter 3.2) by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	
- Operational opportunities	❑	❑	
Is Stator component life extension or modernization (Chapter 3.3) indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	
Is Excitation (❑ Rotary, ❑ Static) life extension or modernization (Chapters 3.4 and 3.5) indicated by:			
- Performance	Yes	No	Comments
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	
Is Rotor life extension or modernization (Chapter 3.6) indicated by:			
- Performance	Yes	No	Comments
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	

Table 3-1 (cont.)
Generation Equipment
Summary of Screening Indicators

Is Bearing life extension or modernization (Chapter 3.7) indicated by:			
- Performance	Yes	No	Comments
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	
Is Terminal or Cable/Bus equipment life extension or modernization (Chapter 3.8) indicated by:			
	Yes	No	Comments
- Performance	❑	❑	
- Age	❑	❑	
- Reliability	❑	❑	
- Maintainability	❑	❑	

3.2 Generator Overall Screening

Output, capacity, age, reliability, maintainability, and operational opportunities of the existing equipment have a substantial role in the evaluation of plant life extension or modernization potential.

De-rating due to failures and deficiencies of major generator equipment is a reason to consider modernization or life extension, and the owner should proceed to Chapter 4, without any further screening, to assess the generator condition.

3.2.1 Performance as an Indicator

The performance or operating capacity of the generator is the most significant indicator in considering a life extension or modernization plan. The actual real and reactive (negative and positive) power output can be compared to the capacity curves of the original equipment manufacturer (OEM) or commissioning tests and any decrease/limitation identified.

Performance as an indicator at the screening level can be obtained from sources including:

- Comparison of actual capacity with OEM or commissioning curves
- Interviews with hydro plant operations and maintenance personnel

Performance indicators are based on questioning:

- Is the unit operating unsatisfactorily (for example, vibration, temperatures, response to controls)?
- Is the output capacity, at rated conditions, less than OEM or commissioning curves (for example, underexcited limit, zero power factor, maximum stator current, overexcited or field current limit)?

A YES answer to either of these questions identifies performance as a driver for life extension or modernization.

3.2.2 Age as an Indicator

The age of the equipment is a major indicator of whether life extension or modernization may be required. Generator equipment that is more than 20 years old should be inspected and considered for refurbishment because insulation systems have a finite life.

Age as an indicator for generator equipment can be obtained from sources including:

- Interviews with hydro plant maintenance staff and technical specialists
- Review of operation databases

Age indicators are based on the following questions:

- Is the equipment more than 20 years old?
- Is the stator winding more than 30 years old?

A YES answer to either of these questions identifies the age of the components as a driver for life extension or modernization.

3.2.3 Reliability as an Indicator

Reliability as an indicator can be obtained from sources including:

- Operation records of forced outages for each unit and each component (that is, the number of outages/year due to generator equipment on each unit)
- Importance of outages/cost of outage in terms of lost energy and ancillary services (that is, whether or not there was a lost opportunity cost due to the outage)
- Number of unplanned outages compared to planned outages for each piece of equipment

Reliability indicators are based on the following questions:

- Is the reliability now significantly decreased compared to the equipment's original reliability?
- Is the reliability now significantly lower than expected?

- Did any recent component failures result in significant equipment repair costs?
- Did any recent component failures result in significant outage (lost revenue) costs?

A YES answer to one or more of these questions identifies reliability is a driver for modernization or life extension.

3.2.4 Maintainability as an Indicator

Maintainability as an indicator for generator equipment at the screening level can be obtained from sources including:

- Records of maintenance outages for each unit (that is, the number of outages/year and duration for planned or regular maintenance of generator components)
- Maintenance records of generator components
- Number and extent of unplanned outages or maintenance outage extensions for each piece of equipment
- Seriousness of extended outages/cost of extended outage in terms of lost energy and ancillary services (that is, whether or not there was a lost opportunity cost due to the outage)
- Comparison of test records for equipment over a number of years

Maintainability indicators are based on questioning:

- Are the conditions found during planned outages significantly worse than expected?
- Does the maintenance outage duration regularly exceed planned or the OEM's recommended duration?
- Have there been false generator trips or numerous failures to start (attributable to equipment) when returning units to service?

A YES answer to one or more of these questions identifies maintainability as a driver for life extension or modernization.

3.2.5 Operational Opportunities as an Indicator

The availability of generation equipment to meet foreseen and unforeseen revenue opportunities or to respond to system needs is another useful indication of life extension or modernization potential. Indicators of operational opportunities for equipment at the screening level can be obtained from sources including:

- Operation records at control centers
- Interviews with plant and utility operations and marketing staff

Operational opportunity indicators are based on questioning:

- Does the generator equipment limit the opportunity for upgrade?
- Has the generator not responded to system requirements (volt-ampere-reactive, megawatt [MW], voltage response)?

A YES answer to either of these questions identifies operational opportunities as a driver for life extension or modernization.

3.2.6 Summary of Overall Generator: Decision to Proceed

Before proceeding to Chapter 4.5, "Condition Assessment of Equipment," verify that screening of the overall generator did not identify equipment that requires additional screening. If further screening is required, see Chapters 3.3, 3.4, 3.5, and/or 3.6 as appropriate.

Alternatively, the results of Chapter 3.2, "Generator Overall Screening," may indicate acceptable operation and the owner may choose to abandon further investigation. If the results are compelling and indicate unacceptable operation or identify modernization opportunities, the owner may choose to proceed directly to Chapter 4, "Performance Evaluation and Condition," and develop an LEM plan.

3.3 Stator Screening

For this subsection, the stator components consist of the frame, magnetic core, and electrical winding.

3.3.1 Performance as an Indicator

Stator performance is critical to the capacity of the generator, particularly between the reactive power outputs affected by the field under- and overexcitation limits. Interviews with operating and maintenance staff can help to determine the existence of any station deficiencies in performance. Questions to ask are:

- Is the stator output at zero power factor (PF) below nameplate current at rated voltage due to temperature rise limitations with rated cooling conditions? See performance curves. (Assumes turbine power output is not a limiting factor.)
- Is there unusual frame vibration or unequal radial expansion (if detectable) at any load up to maximum output?
- Have operations and maintenance (O&M) staff imposed performance limits below OEM ratings?
- Do operators avoid starting and/or stopping specific units?
- Are overheating problems evident during operation within rated conditions?

A YES answer to one or more of these questions identifies stator performance as a driver for life extension or modernization.

3.3.2 Age as an Indicator

Stators less than 20 years old may exhibit deterioration and therefore warrant life extension. Interviews with maintenance staff and technical specialists can help to determine the existence of any defects. Relevant questions to ask are:

- Have routine inspections indicated premature aging (for example, lamination migration, frame cracking, and winding anomalies)?
- Is the stator clean?
- Has the stator winding insulation condition deteriorated over time as indicated by routine winding groundwall resistance and polarization index (PI) tests?
- Has the stator winding internal or surface condition deteriorated over time as indicated by partial discharge analysis or corona probe tests?
- Has unusual core lamination buckling or fretting been observed?
- Have the core bolts being retorqued following observation of lamination looseness, bolt vibration, or flange irregularities?
- Has the stator winding slot wedging system deteriorated or become loose?
- Has displacement or core fretting been observed at core splits?

A YES answer to any of these questions indicates that the owner should consider a full condition assessment of the stator, targeted at further testing and evaluation, as described in Chapter 4.

3.3.3 Reliability as an Indicator

Stators may not have contributed to forced or unplanned outages, but maintenance or technical staff may have reason for concern with continued reliability. Questions to ask are the following:

- Following commissioning and initial problem solving, the unit should have established a best track record for planned and forced outages. Has there been a deteriorating trend based on statistics or anecdotal opinion related to reliability?
- Do operators avoid starting and/or stopping specific units?
- Are overheating problems evident during operation within rated conditions?

A YES answer to any of these questions indicates that the owner should consider further investigation including component condition and protection and control (P&C) screening, which is addressed in Volume 7.

3.3.4 Maintainability as a Indicator

Stators may have contributed to high maintenance costs in both resources and extended outages. Questions to ask are:

- Is there statistical evidence of extended planned outages due to stator work?
- Is the stator requiring extra work (high costs) to maintain condition?

A YES answer to either of these questions indicate that the owner should consider a full condition assessment of the stator (see Chapter 4), targeted at root cause of maintenance work.

3.4 Rotary Excitation System Screening

The excitation system on older machines normally consists of a rotating pilot exciter, field controls, and a rotating direct current (dc) generator. The automatic voltage regulator (AVR) is described in Volume 7. The output of the dc generator commutator is directly connected to the generator field windings via mounted slip rings.

3.4.1 Performance as an Indicator

Rotary excitation systems are frequently slow to respond in comparison to modern static exciters, and they have limited amplitude response. If power system voltage regulation requirements are not met, the rotary exciter performance is a driver for modernization. Otherwise the steady static and step response must be established by asking the operating staff these questions:

- Is the generator output at rated voltage and PF limited by the field current generation at lagging conditions?
- Is pole slip occurring at or near minimum excitation?
- Is the rate of voltage rise and stability (damping) of the generator unsatisfactory when a step response (with AVR on) is signaled? Why?

A YES answer to any of these questions indicates that performance is a driver for life extension or modernization.

3.4.2 Age as an Indicator

Rotary excitation systems are usually more than 30 years old and have significant limitations in time and amplitude response; that is, generator output may not satisfy present day requirements for power system operation. In that case, an immediate decision to modernize may be made and reported in Table 3-1. Otherwise, any deficiencies due to age can be determined from site interviews with staff and technical specialists. Questions to ask are:

- Are the commutator wear components and hardware (for example, brushes, contactors, and motors) increasingly difficult to find/purchase (obsolete)?

- Is the main exciter commutator at the end of its service life (that is, the commutator can no longer be machined or stoned)?
- If a separate pilot exciter is provided, does the commutator still have no residual life?

A YES answer to one or more of these questions indicates that age is a driver for life extension or modernization.

3.4.3 Reliability as an Indicator

Rotating exciters are generally considered reliable because forced outage statistics do not report component data. Station maintenance staff are likely to be the best source of information, and questions to ask are:

- Has any of the rotating exciter equipment failed in service during the last 10 years?
- Have there been observations of commutator operation, for example, sparking and broken parts that require unacceptable maintenance intervention?
- Do the field controls require unacceptable maintenance interventions?

A YES answer to any of these questions indicates that the owner should consider further investigation of life extension, regardless of the study outcome. Advances in brushgear hardware (constant pressure holders) and lifters (for underexcited operation) should be considered.

3.4.4 Maintainability as an Indicator

Rotating exciters are typically a high-maintenance item, in terms of labor, hardware, and out-of-service costs. Local staff operators and technical staff are aware and knowledgeable. Maintainability indicators are based on the following questions:

- Is brush wear excessive? The answer can be based on historic consumption and frequency of replacement.
- Is the commutator patina irregular in appearance?
- Is regular stoning of commutators required?
- Are commutators excessively grooved?
- Does the main exciter commutator runout exceed 0.025 inches (0.635 mm)?

A YES answer to one or more of these questions indicates that replacement of rotating exciter should be considered in both life extension and modernization options.

3.5 Static Excitation System Screening

A static excitation system consists of an exciter transformer phase, controlled rectifiers and controls. For screening purposes, excitation systems using rotating rectifiers will be considered to be “static” if the power is controlled externally.

3.5.1 Performance as an Indicator

The static excitation systems of most generators built after 1970 are capable of providing dynamic machine response for system protection and operation that is better than those built before 1970. Determination of performance as an indicator is based on these questions:

- Is the generator output at rated voltage and power factor limited by the field current generation at lagging conditions?
- Is pole slip occurring at or near minimum excitation?
- Is the rate of voltage change and stability (damping) of the generator unsatisfactory when a step command is applied with AVR on? If yes, why?
- Does the system operation need better response?

A YES answer to any of these questions indicates that performance is a driver for life extension or modernization.

3.5.2 Age as an Indicator

Given the rapid improvements in power electronic devices, a critical and forward-looking investigation of components must be conducted. Age indicators are based on the following questions:

- Are rectifiers obsolete or is replacement cost per unit current high?
- Are replacement control devices for firing control unavailable?
- Does the transformer indicate thermal degradation?

A YES answer to one or more of these questions indicates that age is a driver for life extension or modernization.

3.5.3 Reliability as an Indicator

Solid state power devices are reliable if they are properly applied. However, the age-related process affects the power electronics. Questions to ask the appropriate station and technical staff are:

- Are rectifier failures causing forced outages? Are they causing reduced field forcing?
- Does the exciter control system cause outages?
- Has the exciter transformer failed in service or is it nearing the end of its useful life?

A YES answer to any of these questions indicates that reliability is a driver for modernization.

3.5.4 Maintainability as an Indicator

Static exciters are usually a low-cost item unless there are excessive rectifier failures or there is hybridization due to obsolescence of the equipment. Questions to ask the local staff are:

- Has the maintenance cost (labor and parts) been increasing?
- Have training or other staff costs for troubleshooting and regular testing been increasing?

A YES answer to either of these questions indicates that modernization with new digital-based control technology and new power electronics should be considered.

3.6 Rotor Screening

For this subsection, the rotor components consist of the slip ring/brushgear, leads, field windings, Ammortisseur windings, spider, pole pieces, and cooling (air) provisions.

3.6.1 Performance as an Indicator

The magnetic field produced by a satisfactory excitation system will normally meet the generator electrical capacity requirements unless excessive field current is being shunted through shorted field turns. The mechanical requirements of the rotor are significant to the generator performance. Questions to ask the operators and maintenance personnel are:

- Is the field current and voltage to produce rated generator output outside of OEM or commissioning ratios by more than 5%?
- Is any generator vibration or shaft runout associated with field current changes?
- Is any shaft runout attributable to one-times rotation (that is, once the machine is flashed, does the magnetic field shift the shaft centerline)?

A YES answer to one or more of these questions indicates that performance is a driver for life extension or modernization.

3.6.2 Age as an Indicator

As with stator components, rotor components may exhibit deterioration, even with less than 20 years of service, and require life extension. From interviews with maintenance staff and technical specialists, any deficiencies should be determined. Age indicators are based on the following questions:

- Have routine inspections indicated any apparent deterioration (for example, spider cracking, pole face bluing, and field ground alarms)?
- Is the rotor dirty?

- Has the winding-to-ground resistance deteriorated over time as indicated by lower meggar and PI test results?
- Has any fretting, cracking, or looseness been observed at the spider/rim/pole interfaces?

A YES answer to any of these questions indicates that age is a driver for life extension or modernization.

3.6.3 Reliability as an Indicator

Although rotor-caused failures may not have been statistically recorded, maintenance and operations staff should have knowledge of these events. Reliability indicators are based on questioning:

- Have there been brushgear failures resulting in loss of excitation?
- Have winding-to-ground faults caused unplanned outages?
- Have operating vibration levels increased or changed?
- Have air gap measurements (dynamic or static) indicated any significant variations or changes?

A YES answer to one or more of these questions indicates that reliability is a driver for life extension options.

3.6.4 Maintainability as an Indicator

Brushwear can be expected but there should be limited cost associated with slip rings and miscellaneous rotor maintenance. The rotor, however, is subject to thermal, mechanical, and electrical stresses, and on occasion to overstresses that can lead to considerable cost consequences. Maintenance and technical staff should be questioned as follows:

- Is the rotor winding insulation resistance to ground decreasing? Is it due to dirt/oil or moisture?
- Is brushwear rate increasing?
- Have pole drop tests (if done regularly) indicated increasing turn insulation deterioration?
- Has non-destructive testing of spider welds and attachments indicated defects?

A YES answer to any of these questions indicates that evaluation for life extension should be considered.

3.7 Bearings Screening

The thrust and guide bearings and auxiliaries are susceptible to operator error as well as poor maintenance practices.

3.7.1 Performance as an Indicator

Thrust bearings manufactured prior to 1960 will likely not have lift pump provisions and therefore rely on viscosity and pumping action to ensure proper oil movement on startup and shutdown. In addition, some of these older units may use the braking system for jacking or a lifting thrust collar (journal) to allow oil penetration. Operation, maintenance, and technical staff may be able to provide historic details on the bearing operation. Typical questions to ask are:

- Do the operating constraints on startup, restart, or manual operation limit the energy production (MWh) of the unit?
- Does the operating temperature vary between similar units? Is it greater than 10°C?
- Have there been incidents of cooling system failures?
- Does the operating temperature exceed 60°C?

A YES answer to one or more of these questions indicates that the bearings should be evaluated for life extension or modernization improvements.

3.7.2 Age as an Indicator

Bearing materials and lubricants have improved over the past 20 years. Older bearings are subject to babbit creep, spring fatigue, and pad/plate warping. The operation, maintenance, and technical staff may have knowledge of improvements and evaluations. Age indicators are based on these questions:

- Have there been reasons to consider technology improvements to the bearings, that is, change lubricant type, rebabbit, and replace springs (if applicable)? If so, what was considered?
- Have the hydraulic loading conditions increased since design and installation?
- Have there been incidents of lubricant loss through leakage, vapors, and cooling system?

A YES answer to any of these questions indicates that bearing age should be considered a driver for life extension or modernization.

3.7.3 Reliability as an Indicator

Thrust, upper guide, and steady (if applicable) bearing failures are not well documented. Anecdotal evidence, or lack of evidence, from operators and maintenance staff should be thoroughly researched by the review of maintenance and operations records. Reliability indicators are based on the following questions:

- Has the thrust bearing failed (wiped) since commissioning or during the last 10 years? If so, was the cause design, material, or human error?
- Will the owner’s requirements for availability, repetitive start/stops, or load ramping be changed by increasing bearing reliability?

A YES answer to one or more of these questions indicates that the owner should consider further evaluation for life extension or modernization.

3.7.4 Maintainability as an Indicator

The bearings are a low-cost maintenance item until excessive wear, fatigue, or contamination occurs. The maintenance and technical staff should be questioned as follows:

- Do lubricant samples contain moisture contamination or metal?
- Has the guide bearing clearance maintenance been excessive (that is, do the shoes need to be reset at every maintenance shutdown)?
- Have the accessory devices (lift pumping, cooling system, and lubricant level monitoring) been a high-maintenance cost?

A YES answer to any of these questions indicates that maintainability is a driving force for life extension or modernization.

3.8 Terminal Equipment and Cable Screening

The neutral and line terminal equipment is not likely to be a driver for a generator life extension or modernization program but is included for completeness. However, generator cables may be a limiting factor due to age, condition, and design, and therefore must be screened.

3.8.1 Performance as an Indicator

Conducting components (that is, cables or buses and switches) should be checked for ratings and capacity. Original engineering drawings/specifications may be the best source for conducting component capacity ratings; however, local files and personnel may be easier to consult. Appropriate questions to ask are:

- Have the cables or buses been a load-limiting factor?
- Are there signs of thermal degradation of cables, for example, migration of asphaltic border and necking of insulation near potheads/connections?
- Is the neutral solidly grounded? Modern generators and upgraded units have protection for stator ground faults through a neutral impedance device, for example, transformer and/or resistor.

A YES answer to any of these questions indicates that the owner should consider a life extension program.

3.8.2 Age as an Indicator

This screening can be bypassed if the stator step-up transformer is connected by low-voltage buses or an isophase bus. Questions to ask local staff regarding the stator current transformers (CTs) and cables are:

- Are the cables more than 30 years old?
- Are the cables, CTs, or potheads (if applicable) obsolete? For example, paper-insulated lead covered (PILC) cable may not be replaceable unless spare cable exists at the plant.

A YES answer to either of these questions indicates that age is a driver for life extension or modernization.

3.8.3 Reliability as an Indicator

Because failure of terminal equipment may not be identified in outage data, questioning of operations and maintenance personnel is critical to revealing root causes of failures. Questions to ask are:

- Have the generator cables or buses been replaced or repaired?
- Is there a failure history of the various insulators, potential transformers, or surge protection devices?

A YES answer to either of these questions indicates that reliability is a driver for life extension or modernization.

3.8.4 Maintainability as an Indicator

Other than routine visual inspections, it is unlikely that any maintenance activity will be recorded. However, local staff may have knowledge of equipment condition. Questions to ask are:

- Are the terminal areas dirty, or do they show signs of moisture or other foreign contamination?
- Has there been evidence of overvoltage, for example, flashovers or blown potential transformer (PT) fuses, in the terminal equipment cabinets/enclosures?

A YES answer to either of these questions indicates that maintainability is a driver for life extension or modernization.

3.9 Summary of Screening Indicators

The generator portion of Table 3-1 should be completed, and relevant notes of discussions with operations, maintenance, and technical staff should be attached. If the screening reveals multiple affirmative results, the owner should consider similar turbine screening (see *Hydro Life Extension Modernization Guide, Volume 2: Hydromechanical Equipment*) before proceeding.

If all of the positive results are significant and identify opportunities, these results should be reviewed and evaluated by the owner's technical consultant before proceeding to Chapter 4, "Performance Evaluation and Condition."

4
PERFORMANCE EVALUATION AND CONDITION ASSESSMENT

4.1 Introduction

Evaluations of plant equipment performance and condition are key steps to the formulation of an LEM plan as described in Volume 1, Chapter 4 of these guidelines. Information gathered during the plant screening process (see Volume 1, Chapter 3) and generator equipment screening process for a specific plant (see Volume 3, Chapter 3) is used for the performance evaluation and condition assessment. The LEM process is iterative, and life extension activities are identified in this first stage. The evaluations described in this chapter rely primarily on information and knowledge about the plant or new information that is inexpensive to obtain. Ideally, at this stage of the evaluation, a reasonable assessment of equipment condition can be made without the use of extensive testing and analysis. After the LEM plan is formulated and projects are more clearly defined, additional testing or studies may be justified. These further tests would be included in a feasibility study, as described in Chapter 7, "Feasibility: Optimization of Alternatives." Figure 4-1 is a flowchart that describes how each of the subsections contributes to the identification of activities for the LEM plan.

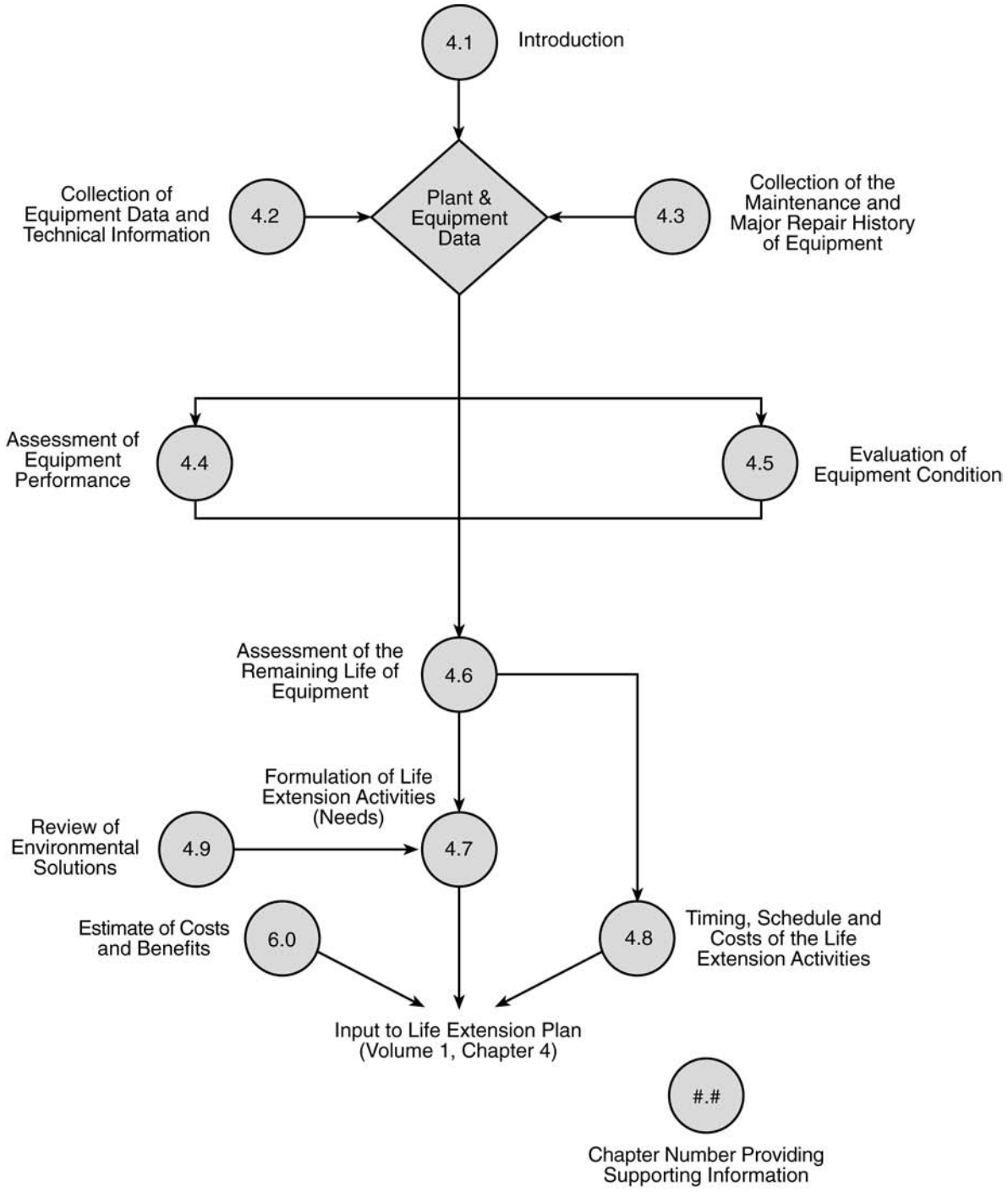

Figure 4-1
Input of Electromechanical Equipment Data to Life Extension Plan

This chapter focuses on the assessment of the performance and condition of the electromechanical equipment and its remaining life as well as on the identification of activities that will extend the life of the equipment. Timing aspects of the identified life extension activities are nominated, and a schedule of activities is formulated. The assembled information from this chapter (Tables 4-3, 4-4, 4-5, and 4-6) is used to develop tables of needs and

opportunities in Volume 1, that are then used to develop the LEM plan. To conduct the condition assessment of each piece of equipment and identify life extension activities, a Site Worksheet for Equipment Condition Assessment (Table 4-1) may be used for convenience, particularly for site visits, before inserting the information into the extensive tables in Volume 1. A worksheet is prepared for each piece of generator equipment based on the asset register assembled for the plant, which is described in Volume 1, Chapter 4.2. These worksheets ensure that all required information for the LEM projects is obtained. This chapter contains the technical information to assist in the completion of the worksheet. A similar table for modernization opportunities is completed using Chapter 5 of this volume.

A depiction of Table 4-1 is presented at the start of each subsection to assist in following the process. The highlighted portion indicates the part of the worksheet addressed in the subsection

Table 4-1
Site Worksheet for Equipment Condition Assessment
Identification of Needs

Plant: _____
Equipment Name: _____
Unit Number: _____
Asset Number: _____
Prepared by: _____ **Date:** _____

Equipment Data and Technical Information (Chapter 4.2)		**History of Maintenance and Major Repairs** (Chapter 4.3)
Performance and Operational Information (Chapter 4.4)		**Condition Assessment of Equipment** (Chapter 4.5)
Risk Evaluation (Volume 1)		**Assessment of Remaining Life** (Chapter 4.6)
Condition Rating (if available) (Chapter 4.5)	**Repairability Rating** (Table 4-5, Chapter 4.5)	**Environmental Issues** (Chapter 4.9)
Possible Life Extension Activities (Chapter 4.7)		**Timing and Costs of Life Extension Activities** (Chapter 4.8)

4.2 Equipment Data and Technical Information

Table 4-1

Equipment Data and Technical Information (Step 4-2, Volume 1)		History of Maintenance and Major Repairs
Performance and Operational Information		Condition Assessment of Equipment
Risk Evaluation		Assessment of Remaining Life
Condition Rating (if available)	Repairability Rating	Environmental Issues
Possible Life Extension Activities		Timing and Costs of Life Extension Activities

When completed, the checklists in Chapters 4.3, 4.4, and 4.5 provide a summary of the technical data and background information required to conduct a general condition assessment of the main mechanical equipment.

4.2.1 Desktop Review

An assessment of the condition or performance of the plant's electromechanical equipment begins with the key technical data that describe the existing equipment. The technical data include equipment nameplate rating information, OEM and engineering references, and dates of manufacture and any commissioning reports. Information or results obtained from the screening phase (see Chapter 3, "Screening") should also be included. This basic information is entered into Table 4-1.

Additional information on design and performance, original O&M instructions, and design changes should be researched and tabulated as an annex to Table 4-1. Information should be added to this resource document as it is obtained. The value of this resource document will be recognized in successive stages of the review and ultimately in the actual design and implementation phase of LEM.

Caution must be exercised when using OEM data because operating conditions, repairs, and previous upgrades may have changed the performance characteristics.

Typical sources of general plant data and equipment information are:

- Equipment nameplates (may not be available until the site visit)
- OEM/Engineering file
- One-line diagrams for P&C
- Drawings (plant layout and elevations): original as-builts and updated revisions
- Generator drawings
- Engineering study reports for original design
- Commissioning reports

- Feasibility studies for original design or upgrades
- Inspection reports of condition and performance
- Environmental study reports

4.2.2 Site Visit

One purpose of a site visit is to verify, where possible, the information obtained from the desktop review of the plant equipment. Another is to verify the history of maintenance and major repairs (Chapter 4.3), equipment performance (Chapter 4.4) and equipment condition (Chapter 4.5) through inspection and interviews with plant personnel. This includes verifying that the asset register is complete and checking nameplate data to ensure that all recorded technical information is correct. Chapter 4.3 of Volume 1 provides additional guidance on the purposes of the site visit.

Site personnel are often the best source of information, particularly when records of equipment and plant operation changes are unavailable or unorganized. Key personnel who can assist in verifying technical data, operating characteristics, and maintenance/upgrade history include:

- Station O&M personnel, including trades supervisors
- Engineering support (technical)
- Previous project managers and retirees

Resources to be researched include:

- P&C one-line diagrams
- Local operating orders
- System operating orders
- Operations reports
- Operating logs
- Technical data books
- Results of investigations into equipment deficiencies
- Commissioning results and reports
- Site test results and reports
- O&M manuals
- Work order history

Some of these sources for the desktop study and site visit may not be available; however, an attempt should be made to obtain original equipment data and upgrade information. Operations data may be available from central sources if data are being compiled to produce statistical performance records.

4.3 History of Maintenance and Major Repairs

Table 4-1

Equipment Data and Technical Information		**History of Maintenance and Major Repairs (Step 4-3, Volume 1)**
Performance and Operational Information		Condition Assessment of Equipment
Risk Evaluation		Assessment of Remaining Life
Condition Rating (if available)	Repairability Rating	Environmental Issues
Possible Life Extension Activities		Timing and Costs of Life Extension Activities

Table 4-2 is an equipment-specific checklist of maintenance and repair work that can form part of an equipment's repair history. It should be used to verify that a complete maintenance and repair history for the equipment has been captured.

Table 4-2
Maintenance and Major Repair History of Hydromechanical Equipment

Asset No.	Equipment	Maintenance and Major Repair Checklist
1.1.4	Generator (overall)	• As-scheduled preventive maintenance per OEM or owner instructions • Structural modifications to design • Regular cleaning and painting • On-line or continuous condition monitoring added • Failure of accessory devices (such as CTs, PTs, lift pumps, and PMG bearings) • Overheating of flexible links or leads
1.1.4.1	Stator	• Winding failure and repair or replacement • Core failure due to fretting or corrosion • Core failure due to thermal stresses (chevrons) • Frame modifications • Circuit ring or connection failure • Re-wedging of stator coils/bars • Core damage due to winding failure • Repair/replacement of side packing • Touchups on grading paint system
1.1.4.2	Rotor	• Field winding insulation failure or replacement • Field winding or slip ring (part of rotor) connections failure or replacement? • Structural failure of rotor spider or rim mounting • Ammortisseur winding or interconnections failure or replacement • Air-gap failure (stator rub, severe vibration) • Pole face or pole tip overheating • Pole iron damage or corrosion • Shorted turns
1.1.4.3	Bearings	• Wiped thrust bearing • Replacement of thrust bearing (very rare) • Replacement of bearing thrust pads or support • Replacement/repair lift pump system • Upgrade protection devices • New thrust pad materials, such as polytetrafluoroethylene (PTFE), used • Lubrication anomalies or modifications (seals, oil levels) • Cooling coil failures • Installation of external coolers • Structural failure of bearing supports • Installed vapor removal system

Table 4-2 (cont.)
Maintenance and Major Repair History of Hydromechanical Equipment

Asset No.	Equipment	Maintenance and Major Repair Checklist
1.1.4.4	Braking system	• Replacement of brake hydraulics system • Addition of dust collection system • Replacement of asbestos-type pads with more environmentally-friendly types (for example, fiberglass) • Change in brake application speeds and design
1.1.4.5	Generator cooling	• Modification to deal with problem of silt accumulation and cooling coil blockage • Design modification • Replacement of cooler • Repair of cooler
1.1.4.6	Generator fire protection	• Fire protection upgrade project
1.1.5	Exciter	• Commutator failure • Excessive brush wear or carbon deposit • Insulation failure of brush holder or winding • Unusual commutator appearance (partial) • Recent replacement with a static exciter or partial upgrade • History of poor patina • Change in brush type or grade
1.1.7	Unit circuit breaker	• Replacement of contact • Replacement of entire breaker
1.1.8	Generator terminal equipment	• Replacement of neutral and/or live current transformer, disconnect switch and resistor bank • Replacement of potential transformer and surge protection device
	Low-voltage cables and buses	• Replacement • Repair

A review of the history of the maintenance and repairs of the equipment and the future plans is an important step in assessing equipment condition and predicting remaining life. If available, the following reports should be obtained for further study to supplement the site visits:

- Annual station reports or year-end summaries for maintenance and capital projects to obtain summary information on changes to the original design and performance
- Station O&M summary records
- Historic cost data (capital and operating)
- Historic annual staff/personnel requirements
- O&M expenditures for the last 10 years

Using the information derived from these sources and guided by the following questionnaire and other searches and interviews, Table 4-2 should be compiled as a summary document and should reference sources by date and location. The questionnaire consists of the following:

- What is the trend in maintenance requirements (such as costs, hours, and downtime) for the equipment over the years? Is the trend increasing? Is it constant? This information should give an indication of condition. A chart of annual maintenance and capital costs separated into the major equipment categories is valuable.
- Are there chronic problems with the equipment, and if yes, what are the problems?
- Does the equipment seem to be a high consumer of maintenance labor and resources?
- Where is the equipment in its life cycle?
- Has the maintenance been superficial, addressing the symptoms rather than the causes of chronic problems?
- What major repairs have been done on the equipment, and did these repairs substantially improve the life expectancy of the equipment? What was the level of rehabilitation?

4.3.1 Personal Safety - Major Repairs

The large currents produced by stator winding failures will result in extreme overheating and burning of the insulation system. Many hazardous and toxic chemicals in the form of fumes and solid particulates are produced by decomposition of the insulating materials when exposed to these high temperatures.

Large quantities of synthetic materials are used in modern generator insulation systems. For example, epoxy resins are used for bonding the mica flakes in the ground wall insulation of stator bars and coils. For machines or windings built in the 1960s or early 1970s, polyester resins may have been used as a bonding agent. Polyester tapes are also often used as a backing for the mica tapes during the manufacture of the stator winding. In bar-type windings, the end caps may be composed of and filled with various types of epoxies.

Although most of the materials typically used in modern generators are self-extinguishing, epoxies and polyesters emit toxic gases such as styrene gas and phenols when severely

overheated. These chemicals can cause problems such as irritation of the eyes, nose, and throat; skin, liver, and kidney damage; and can target the respiratory and central nervous systems.

It should be determined whether asbestos has been used anywhere in the insulation system. Asbestos tape was often used as a protective wrapping on the stator bars/coils in pre-insulation of older machines. If asbestos is present, proper procedures complying with all applicable regulations must be followed in its handling, removal, and disposal.

Before entering a failed machine, it is necessary to follow proper procedures and comply with any applicable regulations so that worker exposure to these hazards is limited. If time allows, venting the failed machine for several hours or days, which assists in eliminating toxic fumes, is recommended. Personnel involved in the initial inspection should consider such measures as limiting their exposure, utilizing self-contained breathing apparatus or masks with high-efficiency particulate air (HEPA) cartridges and organic vapor cartridges, and the wearing of disposal coveralls, gloves, and boots.

Appropriate procedures should also be followed for cleanup, containment, and disposal of the decomposition byproducts and other materials removed from the generator.

4.4 Performance and Operational Information (Records)

Table 4-1

Equipment Data and Technical Information		History of Maintenance and Major Repairs
Performance and Operational Information (Step 4-2, Volume 1)		Condition Assessment of Equipment
Risk Evaluation		Assessment of Remaining Life
Condition Rating(if available)	Repairability Rating	Environmental Issues
Possible Life Extension Activities		Timing and Costs of Life Extension Activities

The tasks described in Chapter 4.2.1, “Desktop Review,” Chapter 4.2.2, “Site Visit,” and Chapter 4.3, “History of Maintenance and Major Repairs,” complement the examination of the running performance of the generator. The examination of operating records and determination of machine operating characteristics is essential to the condition assessment in Chapter 4.5.

An examination of operational well-kept records should reveals how the generator has been operated and any unusual circumstances encountered during its service life. Operating data must be interpreted carefully because anomalies in data and data recording practices can lead to wrong conclusions about the generator’s current operation.

Operating data provide information about the level of use and loading of the equipment that has important implications on the equipment’s remaining life. Equipment that runs at full capacity for most of the year might have a shorter life expectancy than low-load equipment of the same age. Equipment used on a starts and stops basis might have a shorter life span than base-loaded equipment. Operation in turbine-rough zones (higher vibration load levels) may impact equipment condition.

Operational data also provide information on the performance level of the equipment in terms of its reliability and availability. These performance measures can indicate areas where insufficient maintenance is affecting the output of the plant. Volume 1, Chapter 4.7 describes the main performance indicators. The equipment can also be evaluated on its contribution to plant flexibility, that is, how the equipment enables the plant to supply products such as peaking and synchronous condense capability and the importance of its reliability in supplying these functions.

The basic parameters and data for performance evaluation that might be supplemented by specific test reports and measurements include:

- Current Generation Data
  - Generating hours
  - Synchronous condense hours
  - Speed-no-load hours (spinning reserve)
  - Number of start/stop operations
  - Off-line hours (available but not operating)
  - Off-line hours (not available due to maintenance or repairs)
  - Annual net energy (GWh)
  - Annual gross energy (GWh)
- Original Design Data
  - Generator rating (MVA, PF)
  - Maximum generator output (MW) at 1.0 PF
  - Maximum turbine output (MW)
  - Maximum pump power for pump-turbine (MW)
  - Shaft speed
  - Field winding rated voltage (V)
  - Field winding rated current (amps)
  - Pumped storage overall cycle efficiencies (generating energy/pumping energy) for plants with a closed upper reservoir
- Operating Modes
  - Baseload (% time)
  - Peaking (% time)
  - Speed-no-load (% time)
  - Synchronous condense (% time)
  - Pumping (% time) for pumped storage applications

- Current "Off-Design" Operation
  - Overvoltage (%)
  - Stator overcurrent (%)
  - Stator over-temperature
  - Field overloading
  - Out of sync circuit breaker operations
- Reliability Data
  - Number of system disturbance (outage) reports, arranged by cause and the attributed equipment
  - Planned outages (% time), arranged by equipment areas
  - Forced outages (% time), arranged by equipment areas
  - Runaway incidents
  - Fault or short current incidents

4.4.1 Generator Overall Running Performance

For this subsection, *running* is defined as the state of the unit from the initiation of a start sequence, synchronization as generator or synchronous condenser, speed-no-load, subject to system control, loadings or system/unit faults, to the completion of a shutdown sequence. Careful attention should be given to periods of dynamic change or overloads in the running regime. In particular, the data records on temperature, vibration, condition monitoring (if installed), and personnel observation should be carefully reviewed.

Evaluation tests provide additional information about the total generator unit and supplement or complete information not found in the desktop review or site inspections. They also help in identifying opportunities for modernization and deficiencies in life extension plans.

One purpose of using the evaluation tests to assess the current generator condition is to determine the actual capacity of the existing generator. The result might confirm the current nameplate rating, require a lower rating (derating) because of component deterioration, or quite often, determine that the generator has a capacity that exceeds the nameplate rating and existing operation. In addition, operation at lower reactive power limits might allow increased active power output without modifying the existing generator. Therefore, it is important to establish the actual capability of the existing generator as a base case to be compared with life extension and uprating alternatives that require substantial modifications and investment.

The data compiled in Chapter 4.2 may not be sufficient to determine the generator uprating potential because they may not reflect the true present generator conditions. Tests can be performed to determine the actual generator performance even if this documentation is available. Tests 1–3 may be redundant if the plant is under the jurisdiction of a generation/transmission coordinating council such as the Western Systems Coordinating Council, which has its own rigorous test requirements (see Chapter 4.4.5). The detailed tests, inspection, and appraisal of the

generator are tasks that should be performed by a generator specialist, who has the appropriate knowledge and experience. The user should recognize that in some cases the tests may be destructive and that generator component failure is a potential result. These tests are so identified in the related IEEE standard. The tests are as follows:

- Measurement of the open-circuit saturation curve (generator terminal voltage at rated speed, no load, as a function of field current) according to IEEE Standard 115, 1983, Clause 4.2.4.
- Measurement of the short-circuit saturation curve (generator stator current with terminal short circuit as a function of field current) according to IEEE Standard 115, 1983, Clause 4.2.7.
- Measurement of the zero PF (overexcited) saturation curve according to IEEE Standard 115, 1983, Clause 4.2.10. The Potier reactance should be determined by measuring the field current at generator-rated current and voltage and zero PF.
- Measurement of field currents at rated generator voltage and current and various PFs (that is, 0.80, 0.85, 0.90, 0.95, 1.0 underexcited and overexcited) similar to the previously mentioned tests can be conducted at the same time. This test provides valuable information to establish the field coil limitations. In addition, comparison with OEM or commissioning capability curves can establish any operational deficiencies or changes (see Figure 4-2). Caution must be exercised at the extremes of underexcited lagging PF and overexcited leading PF.

Note: The measurements taken in Tests 1–4 can be plotted as illustrated in Figure 3 of IEEE Standard 492, 1974 and shown in Figure 4-3 of this guide. Excitation parameters for anticipated future operating points and a corresponding temperature rise can be determined as shown in IEEE Standard 115, 1983, Subclauses 5.1.3 and 5.1.4, and Figure 14 therein.

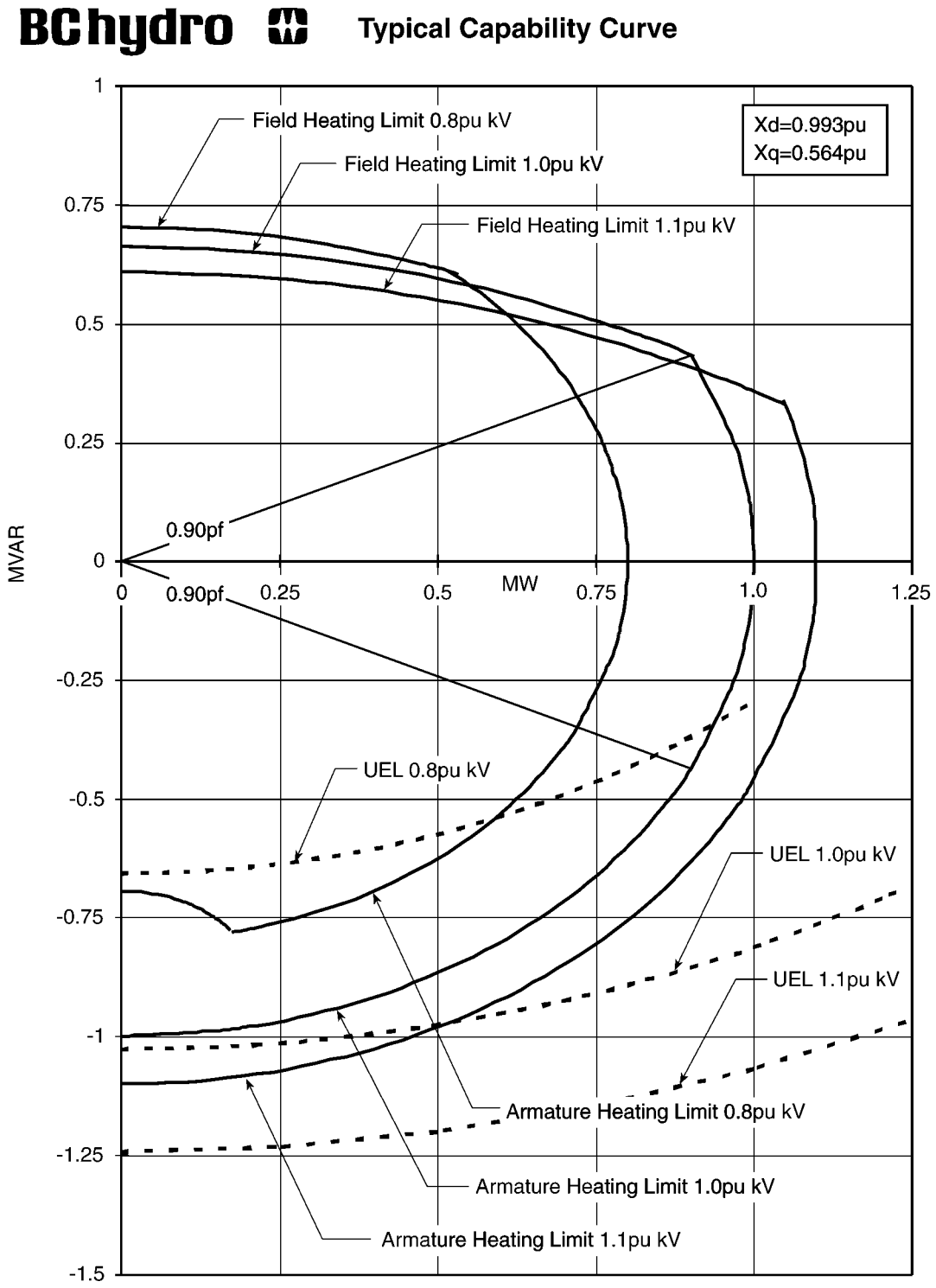

Figure 4-2
Typical Capability Curve

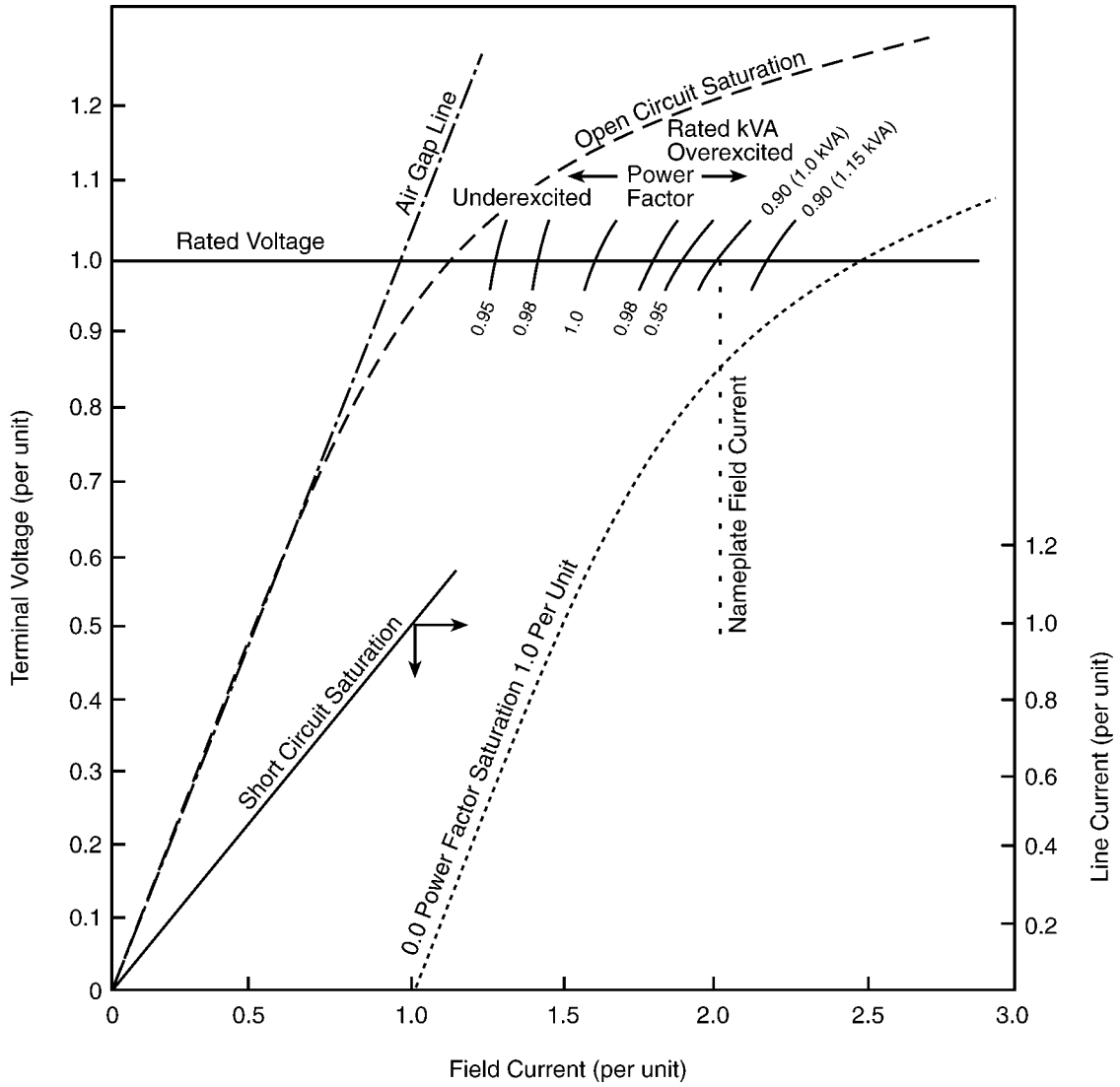

Figure 4-3
Typical Hydro Generator Saturation Curves (0.9 Power Factor, 1.1 Short-Circuit Ratio)

4.4.2 Temperature Data

If previous records are incomplete or unreliable, or if a capacity upgrade or restoration is contemplated, thermal tests (heat runs) should be conducted on the generator and auxiliaries. These test results will serve as the basis for design review and final performance assessment. Measurement of the absolute temperatures and calculated temperature rises of the stator winding can be made using the existing resistance temperature detectors (RTDs). However, the temporary installation of thermocouples and thermometers (remote-reading and/or maximum) and the use of infrared (IR) cameras (optional) are desirable in obtaining comprehensive data on the stator, field windings, ambients, bearings, and cooling water. Expert guidance should be enlisted to

obtain an adequate set of measurements. This is particularly important for indirect measurements (resistance change) such as field windings. Test data should be supplemented by visual inspections, particularly of pole pieces, enclosures, and supporting insulating structures of end turns and ring buses.

Prior to the temperature rise test, the diagrams shown in Figure 4-4 should be prepared to plot stator winding, stator core, and field winding temperature rises. The range of 0 to 80°C (may be extended to 100°C) temperature rise is shown on the ordinate, and the scale on the abscissa should extend to a value of 1.25 per unit (pu). The temperature rise limits corresponding to winding rating can be shown on the diagrams and used as a guide for the test.

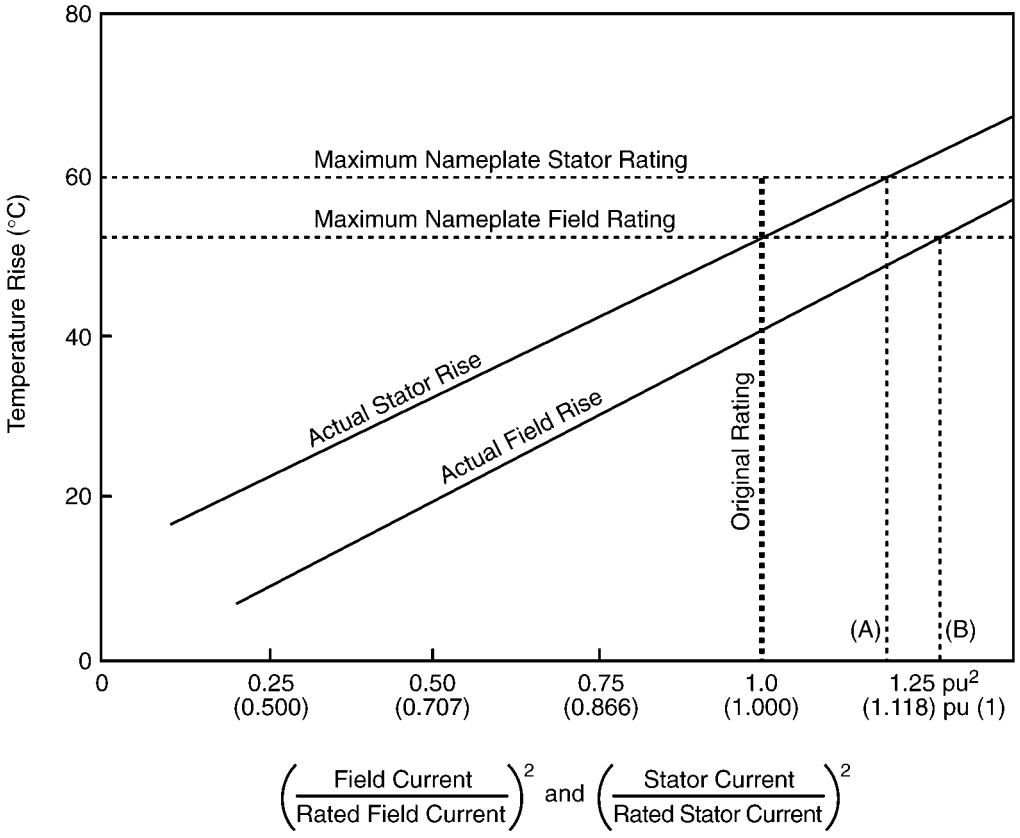

Figure 4-4
Example of a Temperature Rise Versus Stator and Field Current Squared

The temperature rise test should be conducted in accordance with IEEE Standard 115, 1983, Clause 6, using Method 1, “Conventional Loading of the Generator” per Subclause 6.2.1. If loading the generator per Subclause 6.2.1 is not possible because of system dispatch requirements, turbine output limitations, or other constraints, the generator can be operated at less than rated PF (overexcited) to achieve the maximum deliverable or permissible kVA (kilovoltampere) output if the temperature rise values are constantly supervised. The 60°C

temperature rise limit for Class B insulation per ANSI C50.12, 1965 and previous issues[1] may be exceeded by up to 15–20°C at high loads during this test, provided the generator windings and stator core are in good condition and all other potential trouble spots such as excitation equipment, commutators, collector rings and brushes, field rheostat, and exciter cables are constantly monitored.

If the windings are deteriorated or aged, or other restrictions preclude operation at overload or rated load, the temperature tests should be conducted in at least four steps up to the highest permissible load.

The test duration for each load step should be in accordance with IEEE Standard 115, 1983, Subclause 6.3.1. Generally, the methods for measuring temperatures should be in accordance with Subclause 6.4.3 for stator windings and core and with Subclause 6.4.4 for field windings. Preparation for the test shall be in accordance with Subclause 6.5 and all relevant provisions of Clause 6 should be considered when conducting the temperature tests. Furthermore, IEEE Standard 492, 1974, Clauses 5 and 6, and in particular, Subclauses 5.2, 5.4, and 6.1, contain many provisions and much information useful for this task.

The capability of other components such as buswork, circuit breakers, and transformer (bushings) should be evaluated to ensure that they can sustain the expected loads.

4.4.3 Vibration and Mechanical Runout

Determining the mechanical running properties of the unit is important if design changes and/or upgrading are being considered, especially if there is poor history of performance. The most important data are discovered during startup, stabilization, synchronization, ramping to peak loading, and shutdown. The turbine influences in rough zones and initial shaft movements should be noted. The suggested generator components to be monitored include the following:

- Shaft above/below guide/thrust bearings
- Bearing frames if not secured to concrete
- Stator core to frame movement
- Stator frame expansion/contraction as provided
- Pilot and main exciter commutators
- Slip rings
- Air gap (if practical)

[1] The temperature rise limit for Class B insulation was revised to 80°C (75°C above 7000 V) in ANSI C50.12-1982, and the 115% permissible overload range was deleted.

4.4.4 Auxiliary Running Observations

During the tests described in Chapters 4.4.2 and/or 4.4.3, it is prudent to observe other operating parameters such as:

- Main and pilot commutator (brushes) operating condition (for example, sparking).
- Synchronizer operation: The generator should synchronize smoothly to the system.
- Field and unit circuit breakers (CBs): Observe for correct operation and ensure that all flags and indicating devices are operating properly.
- Operation of braking system: The brakes are normally applied when the rotor has slowed to approximately 50% or less but more than 20% of normal operating speed. The brakes should bring the rotor to rest in approximately three to five minutes after application and hold it at rest against the small amount of water leakage past the gates.

4.4.5 Generator/Turbine Unit Tests

Most hydro plant owners of units 10 MW and above will be required by the system operator (regional coordinating council) or independent system operator to provide data for modeling each unit in the integrated operating system. The off-load and on-load responses of turbines, governors, excitation systems, and generator parameters can be established through unit testing. IEEE Standard 492, 1974, "Guide for Operation and Maintenance of Hydro Generators," where data include reactances and impedances necessary in considering machine and winding design changes. The tests also determine other dynamic deficiencies in unit load, speed, and electrical output. If this data are not available, it may be necessary to conduct tests per IEEE Standard 115, 1991 Guide, "Test Procedures for Synchronous Machines," to establish open-circuit, short-circuit, zero PF, and underexcited (line charging) curves and limits. Reference should also be made to IEEE Standard 1434, 2000, "Trial-Use Guide to the Measurement of Partial Discharges in Rotating Machinery" (see Chapter 4.4.1).

4.4.6 Partial Discharge Tests

Partial discharge (PD) activity indicates deterioration in the stator winding insulation system. It can occur internally in the stator winding groundwall insulation due to voids or delamination as well as externally in the slot, end turn, and circuit ring areas. Although the energy of the pulses is minute, the cumulative effect leads to insulation degradation and eventual failure. Discharge activity in generator windings is measured preferably with the machine running so that the winding is under all of the actual electrical, mechanical, and thermal stresses experienced in service. Not only is the magnitude of the discharge load- and temperature-dependent, but various types of discharges respond in different ways to load and temperature. Thus, testing on-line not only provides a more accurate representation of generator condition but also provides some insight into the area where the discharges are occurring (such as slot, internal, and end turns) when the machine is tested under a variety of loads. Off-line tests, where the stator is excited at normal operating voltage, merely provides electrical stresses without simulating the voltage gradient across the winding from line to neutral or the actual phase-to-phase stresses in the slots. It also does not simulate the mechanical (bar forces) and thermal stresses.

The most rigorous PD test was devised by Ontario Hydro. In 1976, the Canadian Electricity Association (CEA) awarded a research and development (R&D) contract to Ontario Hydro to develop an on-line PD measuring system to allow nonspecialized personnel to reliably collect data. Since then, further advancements in analytical software have been developed by various users and commercial interests, and commercial test sets are now available from several manufacturers such as IRIS Engineering and Adwel International. Because new technologies are constantly being developed, a thorough search of potential suppliers should be conducted to ensure that new suppliers are not overlooked.

The CEA PD method uses either temporary- or permanently mounted capacitive couplers. These couplers are directly connected to the stator winding or circuit ring bus and they serve to isolate the detecting apparatus from the power frequency of high voltages while passing the high-frequency discharge pulses. Couplers for machines rated 13.8 kV and below have been made from lengths of 25 kV class cross-linked polyethylene (XLPE) concentric neutral distribution cable and discrete high-voltage capacitors.

Partial discharge analysis (PDA) software is used to count and sort the pulses into several discrete predetermined voltage levels. Through expert analysis and interpretation of the results, a reasonable assessment of the winding condition can be made. Because of the numerous circuits and sources of PD in larger machines, it is not practical to analyze the entire insulation system using a discrete number of coupling devices. Instead, the analysis is carried out on preset areas of the winding, and it assumes that the entire winding is in similar condition due to like age, materials, workmanship, and stresses.

Other techniques have also been developed including a rotary scanner developed by MCM Enterprises under an EPRI R&D project. This technology is now owned by Bently Nevada. This system uses a capacitive pickup mounted on a bridge between the rotor poles. This antenna continuously detects any discharge as the bridge sweeps past the stator winding. In addition to detection of discharges, this system provides thermal scanning and measurements of air gap and acoustical noise.

Radio frequency current transformers applied at the neutral conductor of the generator have also been successfully used to measure the energy produced by these discharges.

Some utilities have used a corona probe (CP) developed by the Tennessee Valley Authority. The test data are useful because the CP checks every slot to provide a detailed diagnosis, but the tests are performed off-line and do not simulate normal operating stresses.

The choice of the PD test method depends on the owner’s assessment of need and cost. The least intrusive and least expensive method is the use of the capacitive PD couplers and PDA software. The on-line PD method requires a significant capital cost but the operating costs are minimal. The on-line PD method is also the most widely used in North America and therefore enjoys good technical support and extensive utility experience.

4.4.7 Ozone Tests

Because ozone is produced by electrical discharges in air, ozone testing provides an indirect method of detecting external PD in the slots, end turns, and circuit ring areas. The circulating air stream is normally tested using Draeger tubes or more sophisticated remote instruments on a regular or continuous basis. Instruments for taking ozone measurements are commercially available. In extreme cases with high levels, an experienced operator will be able to detect ozone even outside the generator housing merely by the odor. Technical assessment of the significance of the ozone levels depends on monitoring other influencing factors such as temperature, relative humidity, and generator loading. Nonetheless, the presence of ozone is not normal and indicates deterioration somewhere in the insulation system. The identification of the source requires other more specific or rigorous tests.

Care must be exercised because exposure to high levels of ozone can be hazardous, and various jurisdictions regulate worker exposure to ozone. Ozone also deteriorates organic and synthetic materials (rubber insulation) and is a long-term hazard to the health of the insulation system.

Additional information about ozone monitoring is in Chapter 5.2.

4.4.8 Air Gap Monitoring

Dynamic air gap monitoring is advisable for the testing of new designs, particularly where the static air gaps have been reduced to below traditional levels. In addition, if runout tests or inspections indicate potential air gap problems (including overheating of rotor field pole tips and stator core end packets), dynamic air gap testing is recommended before assessing the stator condition (frame, rigidity, bearing mounting, and core fixing).

Air gap monitoring is also useful for detecting rotor rim problems such as loss of shrink fit. Distortion of the rotor rim dynamic shape or diameter following application of the field current or following overspeed conditions may be indicative of a lack of proper interference fit between the rotor rim and the spider arms.

There are several suppliers of equipment for dynamically measuring air gap, including Bentley Nevada, Vibro-Systems, Vibro Meter, and BC Hydro International.

4.4.9 On-Line Continuous Condition Monitoring

Few units will be equipped with this technology before upgrading. Nonetheless, the user may want to use some parts of a continuous condition monitoring system before final disassembly of the generator or as part of a deferred LEM plan. See Chapter 5.3.2 for more information on machine condition monitoring (MCM).

4.5 Condition Assessment of Equipment

Table 4-1

Equipment Data and Technical Information		History of Maintenance and Major Repairs
Performance and Operational Information		**Condition Assessment of Equipment (Step 4-3, Volume 1)**
Risk Evaluation		Assessment of Remaining Life
Condition Rating (if available) (Step 4-3, Volume 1)	**Repairability Rating (Step 4-3, Volume 1)**	Environmental Issues
Possible Life Extension Activities		Timing and Costs of Life Extension Activities

This chapter provides supplemental technical information to support the process of developing the LEM plan as described in Volume 1. Initial (screening) assessments might be revised after further detailed studies.

At this stage the owner operator will have the benefit of screening and performance reports (tables and summary support) for the generator as a whole. The technical data indicate the overall generator status and should allow identification of some of the obvious opportunities for repair or upgrade that might require only short outages to change the availability and capability of the unit.

Chapter 4.5 provides detailed instructions on condition and performance information that should be gathered and the criteria (indicators) that are useful for assessing equipment condition. The information about equipment condition can then be fed into a condition rating process, if necessary, or used on its own. The purpose of this process is to develop an LEM action plan without decommissioning the unit through unnecessary disassembly or destructive testing.

Chapter 4.7 describes the life extension activities that could be implemented based on the outcome of the condition assessment.

Various tables are included as examples of the scope and detail to be recorded in the evaluation of condition and performance program. Prior work includes Tables 4-2, “Maintenance and Major Repair History,” 4-3, “Generator Data Sheet,” and relevant attachments.

Table 4-3
Generator Data Sheet

Parameter	Symbol	Unit	Original Design	Present Condition
Rated voltage	V	kV		
Voltage range	ΔV	%		
Rated output	S	kVA		
Rated current	I	A		
Rated power factor	$\cos \theta$	pu		
Rated temperature rise				
Stator - Stator winding insulation - Stator core - Field winding	Δt_s Δt_c Δt_f	°C °C °C		
Stator winding insulation - Brand name - Composition/description - Insulation class				
Field winding - Ground insulation material - Turn insulation material - Insulation class				
Applicable design standards				
Maximum ambient temperature	t_a	°C		
Cooling water - Inlet temperature - Rated flow - Maximum flow	t_w	°C ft^3/s (m^3/s) ft^3/s (m^3/s)		
Efficiency (at rated output)	η	%		
Losses at rated output - Stator winding - Stator core - Field winding - Friction and windage - Stray losses - Exciter losses	 L_s L_c L_f L_w L_{str} L_e	 kW kW kW kW kW kW		
Rated field current	I_f	A		
Rated field voltage	V_f	v		
Exciter current rating	I_{emax}	A		
Exciter ceiling voltage	V_{emax}	v		
Voltage regulating judgement				
Exciter temperature	t_e	°C		
Limitations judgement - Exciter machine armature winding - Exciter machine field coils - Commutators and brushes - Pilot exciter - Cables and busbars - Collector rings and brushes (of main generator)				

The approach to the detailed evaluation of each component will be to start with the stationary equipment and conclude with the rotating equipment. Unless otherwise indicated, evaluation will be performed while the unit is out of service but available for operating. Overall plant safety regulations should be followed during the inspections. Ground fault detectors are necessary in the power supply to the test equipment. Confined space requirements should also be ascertained before entry.

The owner or assessing engineer may choose from several alternative condition assessment processes. These systems have some overlap but may vary in sophistication and degree of detail. Agreement should be established before proceeding, but the objective of completing the tables and ultimately the LEM plan will be based on the assumed validity of this work. The choices are outlined in the following subsections.

The Equipment Condition Assessment Summary worksheet for each piece of equipment (Table 4-1), sometimes referred to as the *site worksheet*, can be a convenient way to collect information, particularly during the site visit. Alternatively, information can be entered directly into Table 4-3 of Volume 1.

The supporting text of Chapter 4.5 provides detailed information on the items covered in Table 4-4, “Condition Assessment of Equipment.” Table 4-4 provides the summary of the technical data requirements, typical assessment parameters, and common life extension activities for each type of equipment.

Table 4-4
Condition Assessment of Equipment

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Life Extension or Modernization Activities
1.1.4	Generator (general)	• Age/operating hours • Type (vertical, umbrella) • Manufacturer • Rated MW output • Rated power factor • Rated voltage • Rated current • Maximum MVA output • Speed • Generator efficiency • Number of starts • Test records for overall running performance • Operating modes See Table 4-3, "Generator Data Sheet"	• Paint/rust condition on enclosures and housings • Vibration • Dust/oil contamination • Brake application • Multiple shaft grounds • Overall running performance tests • Measurement of: - Open-circuit saturation curve - Short-circuit saturation curve - Zero power factor (overexcited) saturation curve - Field currents at rated voltage and current for several power factors • Ozone levels	• Clean and recoat • Rebalance/recenter • Clean and rectify (vacuum systems) • Reduce brake application speed (down to 25%) • Isolate and rectify (temporary: impedance limit in grounding brush) • Replace with new generator

Table 4-4 (cont.)
Condition Assessment of Equipment

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Life Extension or Modernization Activities
1.1.4.1	Stator	• Age • Manufacturer • Frame • Core • Previous heat run test data • Winding - temperature class - type (lap or wave) - coil or bar - material (such as asphalt, mica, and epoxy mica)	• Heat run tests (absolute temperatures and calculated rises) for windings and core • High core losses • Vibration levels • Overheating of core end packets • Thermal distortion (core chevrons) • Looseness: bolt torques, end laminations • High PD (CP, PDA) • Di-electric failures • Mechanical design strength • Circuit ring and connections integrity • Air gap (if practical) • Wedging damage • Absorption and hi-pot tests	• Clean and reset • Repaint/recoat stator and windings • Rebalance/recenter • Provide radial expansion • Retorque bolts • Mitigate and repair corona discharge control coating • Replace individual coils/bars or winding • Recore if winding to be replaced • Rewedge • Repair or replace side packing

Table 4-4 (cont.)
Condition Assessment of Equipment

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Life Extension or Modernization Activities
1.1.4.2	Rotor	• Rating • Rated voltage • Rated current • Number of poles and turns per pole • Ammortisseur design • Slip rings • Air flow design	• Vibration levels • Magnetic umbrella • Rotor/stator concentricity • Integrity of rotor rim shrink fit • Pole drop test • Flux test • Shorted turns • Poor patina • Meggar and hi-pot tests • Overheating of pole tips	• Rebalance • Replace affected pole windings • Re-insulate affected poles • Recenter • Replace rim guidance • Reshrink iron • Re-insulate pole windings • Replace pole pieces
1.1.4.3	Bearings	• Type • Vibration level • Wipes history • Lubrication system type • Cooling system type • Lift pump system type	• High maintenance • Oil and metal temperature rise • Oil pressure and resistance • Insulation resistance • Oil analysis • Shaft runout • Shoe condition • Contamination: brake dust or carbon brush dust	• Check design (oil flow) • Adjust clearance • Redesign cooling: External coolers • Rebabbitt thrust pads • Replace thrust pads • Replace entire bearing (rare) • Replace babbitt thrust bearing with PTFE • Install vacuum system • Replace lift pump system

Table 4-4 (cont.)
Condition Assessment of Equipment

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Life Extension or Modernization Activities
1.1.4.4	Braking system	• Type • Brake application speed	• Reliability of brake application	• Reduce brake application speed (down to 25%) • Replace asbestos pads with fiberglass pads • Install brake dust collection system
1.1.4.5	Cooling system	• Design • Flow rates	• Flow optimization • Corrosion levels • Number of leaks • Condensation problems	• Repair (re-tube) coolers • Repair or replace supply piping • Repair protective coating on piping • Replace coolers: increase size • Improve efficiency and reduce thermal cycling by installing modulating control valves • Re-evaluate design flows and modify system
1.1.4.6	Generator fire protection	• Original design of fire detection and alarm signaling • Condition of generator • Original design of fire suppression • Type of enclosures • Design of powerhouse ventilation to handle generator fire smoke	Adequacy of design for: • Fire detection and alarm signaling • Fire suppression • Generator enclosures • Smoke control	• Testing and replacement of outdated or damaged components • Expand coverage of fire detection and alarming • Replace CO_2 system with water-based suppression if there is a life safety issue • Repair enclosures • Improve enclosures • Improve smoke control systems

Table 4-4 (cont.)
Condition Assessment of Equipment

Asset No.	Equipment or Structure	Description and Background Information	Assessment Parameters	Life Extension or Modernization Activities
1.1.5	Exciter: Rotary or static	• Type of system (rotary, full static, or static pilot exciter) • Commutator brushgear • Rated voltage • Current rating • Temperature rise • Cross-sectional cable area • Efficiencies • Output range • Response time • Drift • AVR rating	Rotary: • Insufficient field for maximum generator output and other operating conditions • Temperature rise • Brush wear rates • Brush current balance • Brush tension • Brush vibration • PMG strength • Poor patina • Availability of parts • Efficiency	Rotary: • Undercut and align brushes • Replace AVR • Stone commutator • Replace adjustable tension brushholder with constant pressure type • Center commutator • Upgrade to brushless exciter • Upgrade to full static excitation system Static: • Install static pilot exciter
1.1.7	Unit circuit breaker	• Type • Age • Rated voltage • Continuous current rating • Interrupting capacity	• High maintenance • Excessive contact wear • Damaged or deteriorated bushings/porcelain	• Filter/replace oil • Replace bushings/porcelain • Rebuild/overhaul to repair insulator problems • Add remote control operation capability • Replace entire circuit breaker with modern design, possibly with increased capacity
1.1.8	Generator terminal equipment	• Stator winding impedance grounded at neutral cubicle	• Condition of disconnect switch, transformer, and resistor bank • Condition of phase terminal devices such as transformers, surge protection, and cable/bus connections	• Replace neutral and/or live current transformers, disconnect switches, and resistor bank • Replace potential transformers and surge protection
	Low-voltage cables and buses	• Type of cable • Cable ratings	• Failure of high-potential tests • Thermal sheath damage • Stand-off insulation damage	• Replace cable • Replace section of cable (splice) • Further laboratory testing to assess condition

Table 4-5 provides a rating system for the assessment of equipment repairability as described in Chapter 4.5.1.

Table 4-5
Equipment Repairability Rating System

Rating	Repair Characteristics
Good	Technical complexity: Easy.
	Testing: Extensive testing or investigation is not required.
	Replacement parts: Readily available and repair does not require the replacement of any major components.
	Cost: Cost of parts and labor is easily justified by restoration of equipment performance and avoidance of replacement costs.
	Outage time: Does not affect total plant outage time, or the increased outage time has no economic impact on the plant (Examples: 1. There is no water available or water can be stored during the extended outage ; 2. Power is inexpensive so revenue losses are very low).
	Deficiencies: Repair would completely solve or mitigate the condition or performance deficiency for a number of years.
	Operations: No further limits on operation result from the repair.
	Access: Parts easily accessible or repair can be made *in situ*.
Moderate	Technical complexity: Moderate. Extensive testing or investigation is not required but some engineering is required.
	Replacement parts: Available and repair does not require the replacement of major components.
	Cost: Total cost of parts and labor is moderate but cost of repair over the next few years can be justified by the avoided replacement cost.
	Outage time: Increases total outage time but plant economic impact of extended outage is low.
	Deficiencies: Repair would completely solve or mitigate the condition or performance deficiency for a number of years.
	Operations: No further limits on operation result from the repair.
	Access: Parts accessible or repair can be made *in situ*.

Table 4-5 (cont.)
Equipment Repairability Rating System

Rating	Repair Characteristics
Fair	Technical complexity: Difficult. Extensive testing, investigation, and engineering (design) required.
	Replacement parts: Available but expensive, or obsolete but can be custom made.
	Cost: Expensive. Total cost of parts and labor is high but replacement is even more costly. Economic justification of the repair is difficult but it may be the only technical alternative other than replacement.
	Outage time: Greatly increased by repair requirements, or even a small extension of the outage time means high revenue losses. There is a significant economic impact on plant.
	Deficiencies: Repairs would only partially or temporarily solve/mitigate the condition or performance deficiency. Increasingly expensive repairs would be required over the years to avoid replacement.
	Operations: New restrictions on operation because deficiencies are only partially repaired (for example, some cavitation repair work such as runner blade reprofiling may result in a new rough zone for the unit).
	Access: Parts difficult to access and must be removed for repair (for example, stainless steel runners must be removed for heat treatment).
Not repairable	Technical complexity: For technical reasons, equipment cannot be repaired (for example, runner made of non-weldable material such as cast iron).
	Replacement parts: Not available (obsolete) and cannot be made.
	Deficiencies: Deficiencies cannot be solved or mitigated (for example, cause of unit rough zones cannot be identified).

Table 4-6 provides typical values of some condition assessment parameters. It should be used as a general guide to the condition of the equipment. When a particular condition assessment parameter exceeds the criteria in Table 4-6, further investigation of equipment condition and performance is advised.

Plant operational data are also important background information for assessing equipment condition. The list in Chapter 4.4 summarizes the operational parameters of interest. Assessment of Condition (Chapter 4.5) and Performance (Chapter 4.4) may be done in parallel.

An example of how to use Tables 4-2 to 4-6 for the condition assessment of a generator stator is provided.

4.5.1 Condition Rating System

The evaluation of equipment condition (its wear and deterioration) is, in part, a subjective evaluation often based on the experience and expertise of the expert. A condition rating system is usually developed to provide an objective means of evaluating equipment condition, although some subjectivity, more appropriately called "engineering judgment," is always a component. Probable life and life expectancy curves, correlated to equipment age and condition, are tools that can be used for recommending life extension activities or equipment replacement once the equipment condition has been established.

4.5.1.1 General Criteria

With any condition rating system, a number of issues need to be carefully considered before using the system in its entirety:

- Condition indices are a tool to help estimate the remaining service life of the equipment. However, service life is not necessarily the same as useful life. Many types of equipment are replaced for reasons other than condition. The concept of "remaining service life" for equipment is discussed in Chapter 4.6.
- The usefulness of tests and inspections "required" by the condition rating system's methodology should always be evaluated. Existing test reports, where available, should usually be relied on at this level of assessment. The suggested test procedures are frequently cited to trigger an investigation into whether or not data on certain condition indicators exist, but the cost of extensive tests is probably not justified at this level of review.
- The concept of "end-of-service life" is difficult to apply for many types of equipment. Diligent maintenance and periodic overhauls can keep equipment functional indefinitely. Although maintenance costs increase and obsolescence of parts can be a problem, replacement can rarely be justified on reduced maintenance costs alone. Therefore, the use of condition ratings to predict end-of-service life is not always justified.
- In many condition rating systems, the overall condition rating assigned to a piece of equipment, such as the generator, is calculated for the component in the worst condition (that is, the component with the lowest condition rating). The objective of this method is to flag equipment with a component in very poor condition. However, the condition rating index

does not provide an indication on the repairability of the component. Equipment may be in very poor condition but easily repairable at low cost and with minimal resource requirements. A second rating system based on repairability is often required to complement the condition rating index. Table 4-5 provides a preliminary repairability rating system.

There are a number of condition rating systems developed for certain hydro plant equipment, and many companies and utilities have developed their own "in-house" systems. Two well-known systems are the REMR program system, which covers most plant equipment, and the Machine Insulation Condition Assessment Advisor (MICAA) system designed for generator and motor assessments. BC Hydro is currently developing an Equipment Health Index (EHI) system for hydro generators and other plant equipment.

4.5.1.2 Repair, Evaluation, Maintenance, and Research Program

The REMR, developed by USACE, is one of the more highly developed condition rating systems available in the public domain. It contains useful information for most types of hydro plant equipment.

The REMR Condition Index Scale establishes a standard definition of condition. It uses a numerically-based scale from 0 to 100. Assessment of condition is accomplished with clearly defined condition indicators. These condition indicators are usually either test results from standard tests or visual or other nondestructive examinations that give a reproducible indication of current condition.[2] The condition rating obtained with REMR or another condition rating system should be entered into the Equipment Condition Assessment Summary worksheet (Table 4-1) in Chapter 4.1 for each piece of equipment so that the condition rating is put into context with other information about maintenance history, performance, and condition.

REMR worksheets for electrical equipment in Appendix D are an example of condition assessment data worksheets. The complete REMR guidelines can be obtained from the USACE if the REMR rating system along with these guidelines are used for the condition assessment. The USACE is planning to update the REMR guidelines in the near future.

4.5.1.3 Machine Insulation Condition Assessment Advisor

The MICAA expert system assists plant maintenance personnel in establishing a predictive maintenance program. MICAA contains the knowledge or expertise to interpret all tests and inspections that can be done on the rotor and stator windings, the stator core, and the rotor body of motors and generators rated 2.3 kV and above. Used by utilities and industry throughout the world, MICAA helps users to predict or diagnose in-service failures, improve winding maintenance planning, and reduce costs.

Developed by IRIS in cooperation with EPRI, MICAA is the product of several extensive research projects on machine testing and maintenance. In addition to calculating the risk of failure, the program also identifies the most likely cause of failure, because this knowledge is

[2] US Army Corps of Engineers, "The Repair, Evaluation, Maintenance and Research Program," March 1993.

used to select the best type of repairs (for example, clearing, dip/bake, and rewind). MICAA calculates the risk of failure from information including test and inspection results, operating history, and known failure mechanisms for a specific type of machine.

MICAA is capable of storing and analyzing a large array of motor and generator data such as test results, inspection data, and O&M history for each particular machine. MICAA data inputs include:

- Machine nameplate ratings
- Temperature and vibration data
- Machine operating hours and start/stop cycles
- More than 100 test and inspections such as PD and flux probe
- Repair history and events

To assist plant personnel in assessing the available data, MICAA has a technical help feature that includes extensive photos and diagrams with explanations of failure mechanisms, detailed procedures for doing inspections, and step-by-step instructions on how to perform and interpret test results. MICAA is available from EPRI.

4.5.1.4 Equipment Health Index

EHI is an end-of-life evaluation process being developed by BC Hydro. It provides information for business planners concerning scheduling of repair, rehabilitation, and replacement projects for hydroplant assets. It provides input into the overall asset planning process.

Technical assessment of equipment consists of two components: health rating (letter grade) and technical prescription.

When the health rating is fair, poor, or unsatisfactory, the technical prescription should state:

- What to do? (major intervention)
- When to do it? (time and tolerance)
- How much will it cost? (budget estimate)
- What are the benefits of doing it?

EHI uses the most recent available data, and the condition is evaluated automatically by a mathematical algorithm based on the key test and inspection data entered into the application. A specialist engineer uses all of the information to provide the health assessment and offers a technical prescription to business planners for the scheduling of capital and maintenance projects.

4.5.2 Condition Assessment of Generator and Associated Equipment

4.5.2.1 Generator Enclosures and Housings

The condition of the enclosure and housings should be examined for integrity and the condition of the protective coating (such as paint and rust). The inspection should be conducted while the unit is operating in order to detect any mechanical vibration or low-frequency oscillation (periodic ringing).

During a shutdown, the unit rundown and brake application durations and any unusual noises or distress should be observed.

Criteria:

Unless operational vibration, noise, and unusual brake application is noted, comments should be limited to cosmetic issues; and, depending on condition, the housings should be rated as acceptable or unacceptable. Operating anomalies should be noted as unacceptable.

4.5.2.2 Miscellaneous Generator Accessories

The shaft grounding brush (if located here or elsewhere) should be checked and the shaft-to-ground insulation resistance (low-voltage) measured if the information is not recorded in Chapter 4.2, "Equipment Data and Technical Information." Any parts associated with operations (such as creep detector, fire suppression, oil vapor collection, brake dust collector, brake air system, and oil jacking system) should be checked.

There are no standards for minimum resistance values. Resistance values are based on experience from satisfactory operation when the bearings show no pitting from carrying current. For detailed information on shaft currents and bearing insulation, refer to IEEE Standard 115, 1983, Clause 3.6.

Criteria:

Oil, dirt, and carbon dust contamination are unacceptable. Oil-only contamination should be noted for possible upgrade of bearing pots. Anomalies in any parts associated with operation are unacceptable.

4.5.2.3 Stator Frame

The stator frame mounting system should be examined from both the coupling room and behind the stator frame (if practical). Particular attention should be given to expansion provisions (if any) and to concrete spalling/cracking. Benchmark status will be important if any upgrade or capacity increase is contemplated.

The stator frame key bars and split joints should be examined for distress. Also at this time, the stator core dovetails should be inspected for fractures, missing tabs, and fretting; and on a

sectionalized frame, the frame splits should be examined for possible distortion, displacement, and fretting.

Criteria:

New cracks in the frame structure or concrete are unacceptable. If uneven expansion is suspected, the stator frame should be rated as unacceptable until further researched (check of negative sequence stator current variation from cold to full load, additional runout, and displacement tests as a function of temperature).

Some keybar and split joints fretting corrosion is acceptable, but excessive and localized fretting or broken bars are unacceptable. Any dirt should be examined for magnetic material, which is unacceptable.

4.5.2.4 Stator Core

The air gap should be visually inspected for lamination protrusions, rubbing, and packet overheating or delamination/fretting. Core bore tightness should be checked using feeler gauges or a knife. Relative core bolt tension may be gauged by striking with a small hammer.

The representative core and clamping bolt torques should be checked and compared to standards or OEM specifications. If field poles are removed to inspect wedging and slots, or when/if rotor is removed for more detailed inspection or repair, core lamination tests should be performed using loop test with IR scanning as appropriate. Although a spot check can be undertaken with Electromagnetic Core Imperfection Detection technology (EL-CID) (available from Adwell International), this procedure is not as rigorous nor is it universally accepted.

The overall core should be checked for core waves, both frequency and amplitude. On a sectionalized core, check core splits for lamination distortion (chevroning), displacement, and fretting. Proper centering of the finger clamps should be confirmed to ensure that there is no migration or other detrimental effects.

Loop tests tend to be effective only if the winding has been removed. Although 15–20 °C deviation is applied on old cores, 10 °C is generally considered the practical limit.

Criteria:

Any protrusion into the air gap is unacceptable.

Deviation of clamp and core bolt torques exceeding 50% of average or less than 80% of OEM specifications is unacceptable.

Loose end laminations, evidenced by fretting corrosion, are unacceptable.

Deviations in EL-CID or loop test temperatures exceeding 10°C rise over average are unacceptable.

4.5.2.5 Stator Winding Inspection and Tests (Rotor in Place)

In many cases, it is necessary to consider the condition assessment of the stator winding as a succession of increasingly rigorous phases, dependent on early observations and test results.

Inspection:

- Inspect the stator air gap with shrouds removed. Check at least the top and bottom wedges for tightness and condition, using a "tap" testing technique. Note any visible fretting corrosion or slot discharge residue.
- Missing or damaged wedging is unacceptable. Loose wedges not exceeding 20% for any slot or 10% overall, on a localized basis, are acceptable but should be noted. Some experts consider that wedges are part of the stator winding. In addition, loose wedges in units rated above 100 megavolt-amperes (mVA) are more critical due to bar forces during unit and system faults.
- Check end winding, twin lashing, and blocking for looseness.
- Inspect the stator winding end turns for evidence of gradient system deterioration.
- Examine the coil or bar and circuit ring connections for deterioration.
- Perform di-electric testing with terminals (neutral and lead) open as soon after shutdown as practical, and preferably before the stator has cooled to room ambient temperature.

Testing:

Test levels: There is a historical significance to de-rating the "as new" or "acceptance" test criteria as a percentage of E, the machine phase-to-phase alternating current (ac) voltage. The acceptance level is based on 2E (kV) + 1 (kV), for example, for a 13.8 kV unit, this is 28.6 kV ac. A common de-rating criterion for in-service units is 75%, or 21.45 kV. Maintenance test levels are often, as per IEEE Standard 56-R, 1991, applied as a factor of E, namely in the range of 1.25 to 1.5, for example, for a 13.8 kV unit at a 1.5 multiplier, this is 20.7 kV ac. Given the slight difference, the evaluator should check the owner's preference or past practice and be consistent in further testing. Since ac testing is usually prohibitive for the owner during the service life, it is customary to refer to the dc level as 1.7 times the ac, although some experts use 1.6 ac to dc for equivalency.

1. Record insulation resistance (1 kV or 5 kV dc for > 6.9 kV ac rating) at 1 and 10 minutes and calculate the PI. Refer to IEEE Standard 43-R, 2000.

2. If the temperature-corrected insulation resistance and PI are acceptable, perform a three-phase controlled overvoltage dc test and compare to historical records if available. Repeat on each phase-to-ground to isolate deficiency if necessary. Do not exceed 1.5 E and stop the test if the current increases nonlinearly. Slot or gradient zone ground-wall failures are a risk. Refer to IEEE Standard 95, 1977.

3. Alternatively, or in addition, perform a one-minute, high-potential, single-phase test. Test power supply may be prohibitive unless a parallel resonant source is available. Do not exceed 1.5 E per phase, with other phases grounded. Observe in darkness, if possible, for areas in end turns to be inspected later. Gradient zone and end turn/circuit ring failure is a risk.

4. Electromagnetic (EM) probe tests. Where access to the air gap is practical, an EM probe can be inserted across magnetic packets while energizing the winding at phase-to-ground ac voltage. Compare to historic data if available. Safety and procedural precautions must be observed due to proximity to line voltage. Refer to IEEE Standard 1434, 2000, Subclauses 6.31 and 11.2.

5. PD testing. This testing is described in Chapter 4.4.6. If the previous four tests described in Chapter 4.5.2.5 indicate deterioration, it may be appropriate to install couplers for future on-line tests.

Criteria:

Limited minor fretting corrosion product or corona residue is acceptable. Localized and heavy deposits are unacceptable.

Ozone levels that exceed national or local safety regulations are unacceptable.

Surface deterioration of gradient systems is acceptable but any erosion of groundwall insulation is unacceptable. Any detrimental effects to ozone should be noted.

Any suspect observation of joint connections (puffing, thermal evidence) is unacceptable.

- DC insulation resistance

  The absolute minimum insulation resistance, corrected to 40°C, is given as (E + 1) megohms, where E is the rated line-to-line voltage. For insulation in good condition, resistance values may be 10–100 times the absolute minimum. PI below 1.5 is unacceptable for Class A insulation and below 2.0 is unacceptable for B and F insulation systems. For complete details, refer to IEEE Standard 43, 2000.

- Controlled overvoltage dc tests

  Not achieving test voltage of 1.25 E without tip-up or failure is unacceptable. Surface discharge (without failure) in end turns is acceptable.

For the one-minute dc test, any failure before 1.5 is unacceptable and calculated (corrected for temperature) resistance below (E + 1) megohm is unacceptable. Refer to IEEE Standard 95, 1977.

- High-potential ac test

  Any slot failure below 1.25 E is unacceptable.

- EM probe tests

  Measurements below 50 mA (milliamperes) are acceptable. Any measurements exceeding 500 mA are unacceptable. Overall increasing trends, average, or local, exceeding 100 mA are unacceptable.

4.5.2.6 Stator Winding Inspection (Rotor Removed)

In large machines, removal of adjacent poles may suffice to provide space to perform the following inspections over the complete bore (height and azimuth). This is also an opportunity to gain information on the core condition.

1. Inspect all slots for wedge tightness and condition using manual means (tap testing) and/or instruments.

2. EM probe test or retest is optional but there is better access to the entire bore with the rotor (poles) removed.

3. If slot discharge is suspect or if its presence is to be checked, select slot(s) to be unwedged on the basis of the EM test, observation, and line and position. Note conditions including thermal degradation, side clearance, and oxidation/discharge products. Measure resistance of slot paint system to ground.

4. In certain cases, and subject to spares and expertise availability, the front leg of a coil or the front bar may be removed and jumpered or replaced as best suited. This enables a more rigorous inspection of the slot portion, core condition, and possible voltage endurance. Laboratory discharge test of ground wall and dissection (cross and laminar) of insulation will assist experts in assessing condition and the failure mechanism and possibly estimating remaining life.

Criteria:

- Wedge/Slot

  Loose wedges exceeding 20% of bore in any slot or 10% of slots are unacceptable.

- EM probe test

  Measurements exceeding 50 mA that are not attributable to visual discharge or where at least one coil is above 50% of line voltage slots are not acceptable.

- Winding

  Slot discharge evidence is not acceptable. Resistance of coil-to-ground exceeding 10 kohms or +100% of average is not acceptable. Side clearances exceeding 0.002 inches (0.051 mm) more than 10% of slot length are not acceptable.

- Coil leg or bar removal

  Erosion of more than 10% of the area of any side slot armor/paint is unacceptable.

  Any looseness of turns or strands is unacceptable.

4.5.2.7 Field Windings and Rotor

Examine the slip rings and brushgear for unusual wear and carbon residue. If the generator is equipped with static excitation, field forcing can raise the voltage at the slip rings up to 10 pu.

Perform the following applied tests:

- With the brushes, the ground protection, and temperature measurement equipment isolated, test the insulation resistance of the field winding and calculate PI as soon after shutting down as practical.
- Pole drop test. Apply an ac voltage across the field winding (usually 120 Vac) and measure the 60 Hz voltage across each pole. Inter-turn insulation defects might show (might need more voltage) low readings (particularly shorted turns), and these poles should be inspected for external contamination. Unless more than two adjacent poles indicate shorting turns, it is unlikely that machine performance will be affected. However, more severe cases may result in reduced output, waveform output (harmonics), and possibly magnetic unbalance and resulting vibration.
- If poles are removed for stator inspection, select on the basis of greater than 10% below average pole drop and perform higher frequency (400 Hz) groundwall power factor tests on removed poles and spares (if available) for comparative readings. Measure turn-to-turn voltage drop at 400 Hz to locate deterioration.
- Inspect all field winding connections and Ammortisseur or damper winding bars, shorting plates, and pole interconnections (if equipped) for tightness and signs of overheating. Ensure that the damper bars are held tightly in their slots and there are no signs of fretting, abrasion, or overheating. If the rotor is removed (not required), ground insulation resistance testing by isolating sections is recommended. Also, more rigorous inspection of damper winding connections and condition of pole ends and core faces might be warranted.
- Inspect field pole-to-rim mechanical mountings for integrity. Similarly inspect the fan ring (if equipped) and blades.

Criteria:

- Field-to-ground insulation

  Insulation resistance at one minute, temperature corrected, less than 1 megohm is unacceptable. Refer to IEEE Standard 43, 2000.

- Pole drop test

  Deviation of two or more adjacent poles by more than 25% of average is unacceptable.

- High-frequency (400Hz) pole tests

  Voltage variation exceeding 10% is unacceptable. PF-to-ground exceeding 5% is unacceptable.

- Inspect items

  Any mechanical or thermal degradation is unacceptable. Thermal degradation is manifested by a discoloration of the components.

4.5.2.8 Rotating Exciter (If So Equipped)

The condition of the main commutator surface, segment insulation, bar shading, and overall patina should be recorded.

The brush wear can be calculated from replacement records.

The brush holders should be examined for tension device condition, clearances, and mechanical alignment.

The pilot exciter should be similarly inspected as well as the main field control rheostat and boosting/backing control devices. Ideally, this equipment and the AVR will have been observed in operation during unit performance tests, described in Chapters 4.4.4 and 4.4.5.

Criteria:

Commutator sparking, protruding mica, bar-to-bar shading, lack of patina, or overheating are unacceptable.

Brush wear rates exceeding 50% of brush useful length per year are unacceptable.

Eccentric or out-of-round commutators and/or slip rings exceeding 0.010 inch (0.254 mm) should be repaired.

Any deficiencies in control apparatus are unacceptable.

4.5.2.9 Static Exciter Transformer

Newer (post-1970) generators may have static excitation systems that use a line terminal transformer bank. These transformers may be dry-type liquid insulated (PCB, mineral oil, or synthetic oil), or gas insulated (SF_6).

Appropriate inspections, tests, and sampling should be undertaken. Lightning arrestors may also be installed.

Criteria:

Any electrical or thermal degradation below accepted standards for the type of equipment is unacceptable.

4.5.2.10 Generator Bearings

Thrust bearings support the axial load on a rotating shaft. On a vertical shaft unit, the thrust bearing supports the entire rotating weight of the unit, as well as any hydraulic down thrust from the turbine. The location and design of generator thrust bearings vary by manufacturer. On vertical units, the thrust bearing is commonly located above the generator rotor (three-bearing units). On umbrella units (two-bearing units), the thrust bearing is located below the rotor. Some European manufacturers incorporate the thrust bearing in the turbine headcover.

Three types of thrust bearing are typically used in hydroelectric units:

- The adjustable shoe
- The spring-loaded bearing
- Self-equalizing

All three of these use babbitt-lined, pie-piece shaped bearing shoes that are pivoted to allow a wedge of oil to form automatically between the shoes and the thrust runner. The difference lies in the supporting structure for the bearing shoes.

The rotating components of a thrust bearing are the thrust block and thrust runner. In most cases the thrust block and thrust runner are separate parts. The thrust block is usually a shrink fit onto the shaft, and the thrust runner is bolted or doweled to the block. On umbrella units, the thrust block is usually bolted to the shaft, and the thrust runner is bolted to the thrust block. The bottom surface of the runner is highly polished to provide a mating surface for the bearing shoes. In some instances, the outer diameter of the thrust runner or block is also polished to provide a bearing surface for the guide bearing. The purpose of the separate runner is to provide a replaceable component in the event it is damaged when a bearing fails.

Most hydro unit thrust bearings are designed for startup and shutdown without the requirement for high-pressure oil lift pump system. However, most use a lift pump as part of the starting and stopping sequences for protection and decreased bearing wear. The thrust bearing high-pressure lubrication system provides high-pressure oil between the thrust shoes and the runner to provide

lubrication on startup and shutdown. The oil is pumped from the bearing oil pot by a high-pressure pump, through a manifold to a port machined in each of the shoes.

To determine the condition of the bearings, some tests can be done without taking the unit out of service. Operational readings such as vibration and temperature data and an oil analysis can provide a signature of condition of the unit. Other tests should be done if the unit is disassembled for other maintenance or repair reasons. The following information is largely taken from the United States Bureau of Reclamation's (USBR's) "Mechanical Overhaul Procedures for Hydroelectric Units: Facilities Instructions Standards and Techniques," Volumes 2–7.

1. Existing Test and Inspection Records (Not Requiring Unit Disassembly)

Pre-shutdown readings provide useful information on bearing condition. Previous reports of the following are useful during condition assessment:

Shaft runout readings - While shaft runout readings can be measured with dial indicators, the preferred method is to install at least one proximity probe at each guide bearing elevation. Readings should be taken at various loads from speed-no-load to full-load including any rough zones and with and without field voltage at speed-no-load.

As part of a unit condition assessment, bearing vibration levels provide an indication of overall unit alignment. In a perfectly aligned vertical unit, the thrust bearing shoes would be level, with each shoe equally loaded, and the thrust runner would be perfectly perpendicular to the shaft. As shaft alignment deviates, vibration and/or runout levels increase.

Bearing temperatures - Bearing and oil temperatures should be recorded at various loads. If a temperature recorder is part of the unit instrumentation, a recording of a normal startup showing the rate of temperature rise should be included. The unit load and wicket gate position should be noted on the recording.

The normal operating temperature of the turbine and generator bearing cooling water supply should also be recorded.

Pressures - The pressure of the thrust bearing, high-pressure lubrication system should be recorded during startup and shutdown. A low-pressure can indicate a failing or failed pump, broken oil supply lines, or in rare cases, poorly adjusted thrust shoes.

Insulation Resistance - The thrust and upper guide bearings of large vertical generators are insulated from the frame to prevent circulating current from passing through the bearing surfaces Test terminals are provided for periodic ohmmeter checks across the thrust bearing insulation. Annual test records should be available. If the insulation resistance is abnormally low, the cause of the trouble should be investigated. Before concluding that the insulating sheets under the bearing supports are causing the low resistance, check the RTD leads, temperature device tube or high-pressure oil connection to the bearing shoes. The thrust bearing insulation resistance should measure from approximately 10,000 ohms to infinity. Low resistance can indicate mechanical damage or damp insulation from leaky cooling coils. Dampness in the oil pot, perhaps due to a

very slow-cooling coil leak or even condensation, can cause serious corrosion damage or saturation of insulation if it is allowed to persist.

Oil Film Resistance - An additional test that can be conducted periodically is to check on the thrust bearing oil film resistance while the generator is running. Although not entirely reliable, this test can indicate metal-to-metal contact where the bearing was slightly wiped or a high spot has developed. Very high resistance with the machine running is a good indication that the bearing surfaces are free of high spots or roughness and the bearing is not grounded. This test can also be used when establishing an oil film with a high-pressure lubrication system to determine how quickly a complete oil film is established on starting a unit or how long it persists on stopping. It can also provide some guidance on the predicted life of the bearing.

Oil Analysis - Bearing oil should be sent to the lab approximately once a year for metal content.

2. Inspection Records (Unit Disassembly)

Records from the most recent unit maintenance overhaul, which involve unit disassembly, should be obtained. The thrust runner should have been inspected for any damage such as scoring on the bearing surface and for any fretting corrosion damage between the runner and the thrust block. If fretting corrosion was severe, the contact area between the runner and the thrust block should be checked. If it is less than 70%, machining is usually necessary.

If there is a history of high temperatures (60°C or historical higher trend), then a detailed examination of the thrust/guide bearings, in addition to maintenance inspection and adjustment, might be warranted. This is also a good time to check the turbine/generator lower guide bearing. Particular attention should be given to the bearing external cooling system or to records of water leakage, including high/low oil levels in bearing pots with internal cooling coils. Bottom oil sample tests may indicate metal contamination. Given the history of bearing failures (reference CEA statistics and other utility experience), it is imperative that the condition of the thrust/guide bearing be evaluated. Refer to previous performance tests on runout, vibration and deflection during excitation, described in Chapter 4.4.3. Any anomalies suggest that consultation with the OEM or bearing experts is required. Web sites of companies such as Kingsbury Bearings offer free technical advice. Further information of bearing lubrication systems is provided in Volumes 4 and 5, “Auxiliary Mechanical Systems” and “Auxiliary Electrical Systems” of these guides.

The bearing brackets and the anchoring system should be inspected for structural integrity. Any cracks should be investigated.

If oil/mist vapor removal systems are in place, they should be checked for effectiveness, whether or not the system has been dismantled, and whether or not oil is dripping in other places from the duct work.

Criteria:

Radial runout during startup and operation that exceeds the cold clearance of guide bearings is unacceptable. Thrust bearing metal temperatures exceeding 105°C or deviating by more than 20°C from identical units are unacceptable. Thrust/guide bearing oil pot temperatures exceeding

90°C (normal is 50–60°C) are unacceptable. A history of bearing wipes that are not attributable to operating errors is unacceptable, particularly if design deficiencies are suspected or evident. Problems with oil mist and/or associated vapor removal systems should be noted.

4.5.2.11 Unit Circuit Breaker

Circuit breakers come in a variety of types including mini-oil, bulk oil, and air blast. Because these breakers are usually located in the powerhouse, dry types such as air blast or "magna-blast" rather than oil-filled types are generally used.

Depending on the configuration, this fault-clearing isolation breaker may be located at the generator line terminal, at a remote location before the unit transformer, or on the high-voltage side of the transformer.

Assessment of the existing apparatus condition should include inspecting the physical condition of the apparatus as well as establishing the adequacy of the ratings for the connected electrical loads. The equipment should be inspected for contamination by dust, dirt, and other foreign material. If the equipment is contaminated, it should be cleaned, with special care taken to remove dirt from all insulators. Contacts on all instrument and control switches and all secondary connections to terminal blocks and other devices and busbars should be checked for any indication of overheating. The switchgear should be checked for blown fuses or burned-out indicating lights and checked in accordance with the manufacturer's instructions. Where space heaters are installed, the heaters and thermostats should be checked for proper operation.

Determining the adequacy of the existing terminal equipment requires a four-step process, as follows:

1. Data Collection - All data relating to the electrical equipment in the system should be collected. This data include power cable lengths, sizes, and impedances; information on connected loads; transformer kVA ratings and impedances; any tie source capabilities; and all switchgear ratings. The effect of any upgradings/upratings must be included.

2. Fault Study - The fault study establishes the continuous and short-circuit currents for the system based on the data collected during Step 1.

3. Load Flow Study - This study establishes the voltage at various points in the system resulting from various loads and impedances in the system based on the data collected in Step 1.

4. Comparison of Existing Switchgear Ratings to Actual System Conditions - The measured and calculated values for the voltage, continuous current, and short-circuit current are compared to the existing switchgear ratings. The comparison should establish the margin, if any, in the existing switchgear.

In addition to inspection of contact wear, there are numerous tests for the determination of the condition of the breaker. The tests chosen will be selected by the type of breaker involved and the rigor and completeness of the condition assessment desired. These include:

- Contact resistance - usually performed with a 50 or 100 amperes (A) conductor to assess the ability of the contacts to carry load current reliably.
- Motion analysis - assesses the overall ability of the breaker to perform its switching and fault clearing requirements. Motion analysis includes such measurements as close travel (this includes overtravel, rebound, wipe, and time), trip velocity and time, and trip-free dwell.
- Correct operation of alarms, pressure switches, and controls.
- Breaker and bushing insulation PF tests.
- Pressure vessel inspections.
- Contact timing tests for multi-break type breakers.
- Inspections of linkages, operating mechanisms, control cabinet, exterior condition, and bushings.

Any mechanical timing conditions as well as thermal or electrical deficiencies are unacceptable.

4.5.2.12 Generator Terminal Equipment

If the stator winding is impedance-grounded at a neutral cubicle, the disconnect switch, transformer, and resistor bank should be inspected. These components are not normally subject to stress, but their mechanical/electrical condition is critical to limiting stator winding-to-ground fault currents.

The neutral, split phase (if applicable), and line current transformers can be subject to damage or deterioration due to overcurrent and poor thermal conditions. The primary connections (usually flexible) and connection surfaces should be inspected for thermal degradation.

The phase terminal enclosure may have several devices warranting attention, namely, potential transformers, surge protection devices, and cable/bus connections. A thorough inspection is necessary. PF testing of the potential transformers and watts loss testing of surge devices (capacitors) at rated voltage may be warranted.

Criteria:

Any mechanical, electrical or thermal degradation, or substandard test result is unacceptable.

4.5.2.13 Low-Voltage Cables or Buses

In many installations, a transfer bus or cable is connected between the generator and the step-up transformer. Cable designs vary in many ways, including:

- Insulation material
- Metallic shield or neutral
- Jacketing
- Accessories
- Operating conditions

For PILC cable, dc potential testing is often used and the PI is calculated. For buses and isophase bus, ac potential testing is used. In either case, the equivalent of 1.5 E ac or the equivalent dc voltage (x 1.6) should not be exceeded.

The purpose of condition assessment is to use any existing test data, design information and known operating conditions for the cables or buswork to make a best estimate of the remaining life. If no test data are available, or if testing has not been performed in the last three to five years, it might be useful to perform condition assessment testing. The following discussion includes some of the test data useful for the assessment and guidance on further testing. Further information specifically on PILC cables is provided in a tailored collaboration project, 1000741, *Condition Assessment of Distribution PILC Cable Assets*, 2000. The topic of XLPE-insulated cables is addressed in TR-114333, *Review of Emerging Technologies for Condition Assessment of Underground Distribution Cable Assets*, 1999.

1. Insulation Condition

Although insulation failure is usually the final breakdown mode in cables, it is rarely the primary cause. Cable insulation is often subjected to severe conditions including contaminated water, overheating, factory defects, damage during installation, and higher than rated voltage stresses. Any of these may in time lead to insulation breakdown and therefore what surrounds the insulation and how the cable was operated are important factors to note in the condition assessment.

Assessing insulation condition may be performed in the laboratory, on cable samples, or on-site, using one or more electrical tests. Laboratory assessment is useful for the assessment of remaining life, as described in Chapter 4.6.7.

On-site condition assessment involves an electrical test, usually performed on de-energized cable systems. There are currently a number of tests available, including partial discharge, dissipation factor, voltage recovery, and leakage current measurement. Unfortunately, no single test reveals the complete condition of the cable insulation.

Powertech Labs has developed a low-voltage dc test method - Leakage current (I) pico Ampere test (LIpATEST) - that has been used successfully to assess the condition of XLPE cables. The test voltage is less than half of the recommended levels for aged cables using traditional dc Hi-Pot testing. The LIpATEST requires less than 10 minutes to perform and the maximum dc voltage is applied for only 1 minute. The LIpATEST is used for on-site insulation assessment, along with other tests to assess the condition of cable jackets and shields.

2. Metallic Shield or Neutral Condition

Cable metallic shields or neutrals may suffer mechanical damage during installation, or over time from temperature cycling, particularly under cable clamps. Corrosion can also be a serious form of shield damage. In general, the thinner the metallic shield the more susceptible it is to damage or corrosion. Copper tape shields are particularly susceptible to damage and corrosion, even in fully jacketed cables.

Metallic shield damage may result in heating of the underlying semi-con shield and insulation, which increases voltage stress and accelerates insulation failure. Damaged or corroded shields may be found in a dissection during failure analysis. In an on-site condition assessment, there are specific tests designed to examine the extent of metallic shield or neutral damage.

An initial assessment of the cable neutral or shield is made with a dc resistance meter. If the resistance reading is high, Low-Voltage Time Domain Reflectometry (LVTDR) can be used to locate the points along the cable where the neutral or shield is deteriorating. LVTDR is a very low-voltage technique (10 V pulse) and does not harm the cable in any way. The LVTDR test equipment is small and easily transportable.

3. Cable Jacket

The cable jacket can be compromised during installation or handling of the cables. A damaged jacket is often a first indication that further problems might be encountered. Water ingress in the cable causes neutral or shield corrosion and water tree development in XLPE insulation that eventually leads to premature cable insulation failure. Several simple on-site tests can be used to assess the overall condition of the jacket.

4. Cable Accessories

Cable accessories, including joints, terminations, and separable insulated connectors (elbows), are some of the most vulnerable parts of an installation. Failure mechanisms in accessories are varied, but one of the most common causes of failure is improper installation.

To determine the condition of accessories on site, two symptoms are usually assessed: elevated operating temperature and presence of PDs. Accessory operating temperature can be measured with fiber optic probes or IR techniques, and are best made under the highest possible circuit loading. Even the poorest connector in an accessory will not get hot if it is carrying little or no current.

PDs can be measured and these sites located using a number of off-line or on-line techniques. Off-line PD techniques can use higher than normal voltage to determine possible impending failures. On-line techniques use the normal operating voltage, and so detection of PD indicates the accessory is closer to failure. Of course, on-line techniques have the advantage of not requiring an outage.

5. Operating Conditions

One operating condition that can seriously affect cable life is elevated temperature. Cable systems are normally designed to operate at a maximum current. The design maximum current is based on cable size and installation conditions. The design maximum current is usually derived in a conservative fashion to allow for possible hot spots caused by unknown conditions or additional heat sources. Consequently, operators do not usually know the exact cable operating temperature. Lack of this key information can mean:

- Failure of the cable at an unknown hot spot
- Under-utilization of the cable system

Knowledge of temperature at all points along the cable is now possible using Distributed Fiber Optic Temperature Sensing, a system which can measure the temperature at all points along an optical fiber. If an optical fiber can be installed in a duct along a cable run, then exact locations and temperatures of hot spots can be determined. This can be a cost-effective method of preventing failures on heavily loaded feeders by mitigating conditions at hot spots. Knowing the exact temperature of a heavily loaded feeder might allow deferring of a new cable installation.

Criteria:

Any di-electric high potential test failure is unacceptable. PI of less than two is unacceptable. Any thermal sheath damage or stand-off insulation damage is unacceptable. Leaking oil is unacceptable.

4.5.2.14 Protection and Control System

The P&C system should be reviewed and the as-found status summarized. All cabinets should be inspected for wire condition, housekeeping, and good maintenance practice. Drawings should be up-to-date and should represent the actual P&C wiring. Maintenance and test records should be checked. See Volume 7, “Protection, Control, and Automation” of these guidelines for more information.

Criteria:

Any operating anomaly is unacceptable.

4.5.2.15 Generator Cooling

There are three main designs for generator cooling:

- The most common design consists of surface air coolers on the stator frame; cooling water is usually taken off the penstock, and rotor fins recirculate the air.
- Normal air ventilation is a design that does not provide any coolers. Cold air from the tailrace is pumped through the unit by the rotor fins (non-recirculating). These systems expose the units to considerable dirt, and maintenance issues can arise.
- For large, modern machines, sometimes the cooling water tubes are embedded in the stator coil. Cooling water is usually taken from the penstock.

If water-cooled, the generator is the largest consumer of cooling water. Cooling water systems for generators are usually unchanged from the OEM's specifications when the station was commissioned. These systems are often conservative with flow capacities that greatly exceed the cooling requirements of the unit. Condition assessment of the system consists basically of evaluation of the condition of valves, piping, and the generator coolers. Age and water quality are the two significant factors that affect cooling water equipment. Certain water qualities can lead to aggressive corrosion of the pipes and valves, especially if microbial activity is involved.

Assessment of the cooling water system should begin with a review of the auxiliary cooling water system's maintenance history. The type and frequency of failures will identify those areas that may require attention. The valves, strainers, intake, intake screen, and piping should be visually inspected for blockage, leaks, and excessive rust or corrosion. When the system is inspected, the appropriateness of material selection should be an important factor.

All valves and strainers within the system should be checked for condition and proper performance. All water filtering systems should be inspected to ensure that the system is removing the necessary debris from the water. Automatic backwash systems should be checked for proper valve operation and backwashing of debris from the filters. Proper setting of the differential pressure control for initiating automatic backwash should be verified.

The generator air coolers should be checked for leaks, corrosion and mineral buildup. The maximum pressure differential across any of the coolers should be approximately 10 psi (68.9 kPa) to ensure satisfactory cooling.

Cooling water piping should be also checked for leak-tightness, corrosion, and mineral buildup.

If constant blockage of pressure-reducing valves and radiators is a problem, further studies should be conducted to assist in the formulation of a solution. Some cooler valves should allow throttling to avoid or reduce condensation occurring on the outside of coolers and dripping into the generator housing.

Additional description of cooling water systems are provided in Volumes 4 and 5, "Auxiliary Mechanical Systems" and "Auxiliary Electrical Systems" of these guidelines.

4.5.2.16 Generator Fire Protection

1. General

This overview of fire protection for hydroelectric generators in existing power generating stations is to be used as a guide when assessing the condition of existing generator fire protection. However, the ability to recognize fire hazards, identify system deficiencies, and recommend effective upgrades can only be developed through education and experience. Furthermore, a guide is only a general statement of principles and methods. A strong technical background in fire protection is necessary to perform an effective audit of fire protection for generators.

The probability of a fire in a hydroelectric generator is low. Subsequently, fire is seldom perceived as a threat, and fire protection is often inadequate or not provided at all. There is the potential for a catastrophic loss when a fire does occur.

A generator is a significant fire hazard due to the large amount of combustible winding insulation. The high voltage in a generator creates a potential ignition source. Intermittent or sustained electrical arcing will lead to a fire within the generator.

A generator fire can cause injury, inflict substantial property damage, spread fire to other areas of the station, and significantly impact the ability of the station to generate electricity for a long duration. A condition assessment of generator fire protection should determine what was installed, its design objective, and the current condition of the existing systems.

If the original design is adequate, life extension of the systems should be considered; but if there was limited fire protection in the original installation, or if the original system is no longer adequate, modernization should be considered.

In assessing the condition of generation protection, there are five important points to consider:

- What is the condition of the generator? A condition assessment of generator equipment is best performed by a specialist in the generator field; however, at a minimum, the relevant items with respect to fire are a history of faults or malfunctions, previous fires, and deterioration in the rotor and stator winding insulation. If the root causes of generator malfunction can be addressed, the risk of a fire will be significantly reduced.
- Has a fire detection and alarm signaling system been provided for the generators? What was the original design and installation? What is the condition of the existing installation?
- Has fire suppression been installed for the generators? What was the original type and design of the system? What is the condition of the existing fire suppression system?
- Is there an enclosure around each generating unit to separate the unit from the general powerhouse? What was the original construction of the enclosure? Was it constructed as a fire separation? Was a fire-resistance rating provided? Are service penetrations and openings protected by fire stop systems and closures having a fire protection rating? What is the current condition of the enclosure?

- Generator fires produce large quantities of toxic smoke that can quickly incapacitate personnel and damage other equipment. How is ventilation provided for the powerhouse? Was smoke control part of the original design? Is the design philosophy behind the smoke control system sound? What is the condition of the existing smoke control components?

A comprehensive review of generator fire protection must account for all of the noted items.

2. Fire Detection and Alarm Signaling

To detect generator malfunctions, units are provided with electrical P&C systems to detect operation outside of normal range.

The fire detection system complements to the electrical protection systems. For example, if the thermal detectors in the windings detect an abnormally high temperature, the protection can operate the circuit breakers to disconnect the generator from the power system and open the field circuit.

If the electrical protection system fails to prevent a generator fire, then the fire must be detected and action initiated. Personnel must be alerted to a potentially dangerous emergency situation, and the generator fire suppression system and station smoke control system need to be activated.

If fire detection and alarm signaling systems are to undergo testing as part of the condition assessment, steps should be taken to isolate the system to prevent unwanted operation of fire suppression systems or other station equipment. Personnel and station control must be informed that testing will be taking place.

When assessing the condition of the existing fire detection, there are a number of important points to consider:

- Is the station equipped with a fire detection and alarm signaling system? Is the unit equipped with a dedicated fire alarm control panel? If installed, does the station fire alarm monitor the unit fire alarm control panel or does it monitor the generator fire detection devices directly? What is the make and model of the unit fire alarm control panel and station fire alarm system?
- Has fire detection been provided specifically for the generator? What types of detection devices are provided? The basic objectives for all detectors are similar: they must be able to detect a fire condition, and they should be able to distinguish between products caused by a fire (that is, smoke and rapid rise in temperature) and ambient conditions (that is, dust and moderate temperature fluctuations). A basic principle of effective detection is to have multiple detectors at various locations in generator enclosure.
- Thermal detectors can operate on three different principles: alarm signal when air temperature exceeds a pre-set value, alarm signal when rate of temperature rise exceeds a pre-set rate, or a combination of temperature and rate-of-rise criteria. Thermal detectors are reliable and are generally resistant to false alarms. Thermal detectors generally do not require maintenance, but some models are designed only for a single exposure and must be replaced after being exposed to high temperature; thermal detectors should be checked to determine their type.

- Are smoke detectors provided? Smoke detectors are more sensitive than thermal detectors, and therefore, they give an earlier warning of a fire condition. They can also be prone to false alarms from dust and particles similar in size to smoke particles. Duct-type smoke detectors should be used for generators because they are specifically designed to detect smoke in moving air. Smoke detectors should be tested with a test aerosol to ensure proper operation.
- The location of detectors should be reviewed. Due to the multitude of generator configurations, there is no common point for detectors to be located; however, according to a general principle, detectors should be installed so that they are in the path of air flow through the generator.
- Are there old-style, 120 V, ionization-type smoke detectors present? These devices use a radioactive element and are therefore a health hazard if the element leaks and must be handled extremely carefully. They should be removed and returned to the manufacturer in compliance with nuclear/atomic energy regulations for handling of these devices. The more modern photoelectric-type smoke detectors do not use a radioactive element and are less prone to false alarms than ionization-type smoke detectors.
- Is the detection system interconnected to the electrical protection? For example, the lockout relay contacts should provide a signal to the unit fire alarm control panel. In this manner, the presence of a generator fault can aid in the "decision" by the control panel to operate the unit fire suppression system and alert the main fire alarm panel to initiate a general alarm throughout the station.
- Is the powerhouse equipped with linear beam detectors at the ceiling of the generator hall? Is adequate coverage provided by the beam detectors? Are the beam detectors calibrated properly?
- Are there any other detection devices in the powerhouse that would detect a generator fire? What was the original purpose of these detectors? Do they still serve an important function? How are they connected to the unit fire alarm control panel or station fire alarm panel?
- How are personnel alerted to an emergency condition? Has audible signaling been provided? Can the audible signals be heard over ambient noise conditions (including potential sound cancellation)? Is visual signaling provided, especially in areas where audible signaling is not audible?
- Is the fire detection and alarm signaling system connected to an emergency power supply? How long can the emergency power supply provide supervisory operation? How long can the emergency power supply operate the system in full alarm mode? The simplest method of providing emergency power is to install battery packs in the generator fire alarm control panel.
- Do the detectors provide a pre-alarm signal to the main fire alarm panel to permit a manual response to an alarm condition and to provide an early warning in the event of a fire?
- If the generator is equipped with a fire suppression system, is the system activated by the unit fire alarm control panel or the station fire alarm? Is the system monitored for operation, tampering, or leakage by the unit fire alarm control panel or the station fire alarm?

- Does the fire detection and alarm system have the ability to control the heating, venting, and air conditioning (HVAC) and smoke ventilation systems? A generator fire produces a large amount of smoke in a short period of time, and ventilation should be activated as soon as possible. By having ventilation operated automatically by the fire detection and alarm system, ventilation can begin at an early stage.
- Is the station fire alarm panel monitored from a remote alarm monitoring agency or a utility control center? Remote monitoring is an important consideration for stations that are unattended for periods of time. Remote monitoring also allows a utility to formulate a quicker response to an emergency situation by automatically informing an outside control center of an emergency.

3. Fixed Fire Suppression

A fixed suppression system inside the generator is necessary because a protection and control system is not always activated early enough to prevent ignition. A fire must be suppressed to prevent further damage to the generator and prevent the spread of fire to other parts of the station.

In general, fire suppression systems include water-spray deluge, halon, replacements for halon, carbon dioxide (CO_2), and argon-based systems. Water-spray deluge and CO_2 systems are the most prevalent systems. The other systems are not commonly installed on generators, and therefore, they will not be considered further in this guide.

Water-spray deluge systems inject very small water droplets into the generator. The small droplet size and the windage created by the rotor distribute the droplets through the generator and rapidly remove heat from a fire, thereby suppressing the fire.

Due to the incompatibility of water and electricity, there has been resistance to the use of water-based systems in generators. However, experience has shown that the water damage resulting from deluging a unit with epoxy-based insulation is minimal. Water-based systems have demonstrated effectiveness in extinguishing generator fires, and at a hydroelectric station, there is an essentially unlimited supply of water.

Other than water-spray deluge, carbon dioxide systems are the most common fire suppression systems.

CO_2 is a gas at atmospheric temperature and pressure. It is a natural, albeit small, component of the atmosphere. A CO_2 system works by reducing the oxygen content to a level below that which will support combustion.

There are two classes of CO_2 systems: a local application system and a total flooding system. A local application system is not practical for a large hazard such as a generator and will not be considered further in this guide.

Total flooding is a method that injects a sufficient volume of CO_2 into the generator enclosure so that an inert atmosphere is created. A total flooding system is custom-designed for the specific application. The quantity of CO_2 required is based on the percentage concentration (by volume) required to extinguish a fire in the type of equipment being protected. A total flooding system will not be effective if there is no enclosure or if the enclosure has significant leakage. There are two types of total flooding systems: high-pressure and low-pressure.

A high-pressure CO_2 system consists of a battery of cylinders connected by a manifold and connected to distribution pipe terminating in special discharge nozzles.

A low-pressure system differs from the high-pressure system in that instead of storage cylinders, there is a tank of CO_2 kept at low pressure and temperature through the use of a refrigeration system. This design requires less space than a high-pressure system, but there is the potential for the refrigeration to fail, in which case the CO_2 will expand and require venting to the atmosphere.

The standard for these systems is National Fire Protection Association (NFPA) 12, "Carbon Dioxide Extinguishing Systems." NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume. A major concern with CO_2 is its hazard-to-life safety, the concentration of CO_2 required to extinguish a fire is much greater than the concentration required to incapacitate or kill a person.

Rotating electrical equipment requires extended discharge of CO_2. Extended CO_2 discharge is introduced into the generator enclosure at a slower rate than the initial discharge to protect rotating electrical equipment against possible agent losses during machine deceleration or rundown. It requires an additional quantity of CO_2 more than that needed for the initial discharge.

CO_2 systems were once used extensively in the hydroelectric industry, but they are not generally used for new installations due to life safety hazard, expense, and questionable effectiveness.

When performing a condition assessment of a fire protection system, the following important points should be considered:

- Is there a fire suppression system, and if so, what type of system is installed? Water-spray deluge and CO_2 systems are the most prevalent.
- What was design objective of the system currently installed? Was the initial design adequate?
- What is the condition of the existing installation?
- What is the maintenance history of the fire suppression system? Was it properly tested and commissioned, and has it been inspected and tested on a regular basis since then?
- Is the system controlled and supervised by the fire alarm system? For example, will leakage in the fire suppression system be detected by the fire alarm control panel?
- Does the system have both automatic and manual activation capability? Automatic operation is provided by the fire detection and alarm system in conjunction with the unit protection and control. Manual activation is generally provided by an operating handle or other controls at the deluge valve.

- If manual activation is provided, are the manual activation controls identified and in a conspicuous location? Is there some means of preventing accidental operation of the manual release? There have been instances of the opening of a deluge release valve because of accidental physical contact or because the controls were poorly identified.
- Water-spray systems are equipped with manual shutdown, but CO_2 systems are not always provided with this feature. If a CO_2 system is installed, is it equipped with an abort switch for manual shutdown?
- Is the manual shutdown identified and located in a conspicuous place?
- Can the system be disabled to prevent undesired operation during maintenance?
- What is the condition of the fire protection piping? Has fire protection piping been seismically restrained? Fire protection piping must be bonded and grounded in order to prevent the creation of voltage potential and an electrocution hazard.
- Check that pressure gauges are reading correctly and that they display the required pressure.
- All fire suppression systems should be supervised by the unit fire alarm control panel or the station fire alarm panel for discharge and tampering. In most cases, the operation of the fire suppression system should be interlocked with the fire detection system to provide automatic activation.
- What is the degree of conformance with NFPA 15, "Standard for Water Spray Fixed Systems for Fire Protection," if a water-based system is installed?
- If a water-based system is installed, is the system designed to provide a spray of water droplets directly onto the insulated portions of the upper and lower winding structures including the stator windings, stator terminals, circuit rings, winding endheads, field windings, and damper windings? Does the water-spray system use a ring with discharge orifices, or is it a newer-style system with discharge nozzles? What are the condition, coverage, and applied density of the deluge system?
- Check the age, make, and model of any existing water deluge valves. Some of the early-style deluge valves were complicated and have a history of O&M problems. Check that the valve used is listed and approved for use by a recognized testing agency.
- Some of the older-style water deluge systems incorporated a compressed air line. The objective of installing this line was to atomize (reduce) the size of the water droplets expelled. However, in practice, this arrangement was problematic. It often does not produce the desired effect; and if there is a significant pressure imbalance, it can actually prevent water discharge. It is normally recommended that these compressed air lines be removed.
- If a water-based system installed, is the system set for cycling operation? The system should shut down after a set period of time if the thermal detectors have reset by the end of the cycle. If the detection system identifies another fire condition, the system should then operate again. If the system is not set for cycling operation, then the system will continue to discharge water until it is shut down manually.
- Is there a test loop for the water-spray deluge system that is piped directly to drain to permit testing?

- Is the water supply adequate? All valves for the fire protection water supply should be supervised by the station fire alarm system. Also, the fire protection water supply should not be affected by shutoff of domestic water or other service water supply. Pressure-reducing valves and other components must operate correctly so that they do not impair the ability of the system to provide required flow and pressure. Is the system capable of providing water to multiple systems? For example, a manual hose station operated at the same time as a deluge system places additional demand on the water supply system.
- Low water pressure renders a deluge system ineffective. Pressure loss in pipe can be reduced through the use of large pipe, use of stainless or galvanized pipe, selection of proper valves and fittings, and good design. If testing indicates that the water flow and pressure available at the generator is inadequate, the components of the water supply system should be examined for these features.
- In spite of efforts to reduce pressure losses in pipe, stations with a low head might require a fire pump to boost water pressure. If there is an existing fire pump, what type of pump is it? Both the pump and motor should be listed by a recognized testing agency as being suitable for use as a fire pump; a label on the apparatus indicates this feature. Diesel and electric pumps are acceptable, but special consideration must be given to diesel fuel storage to ensure that it is not a fire hazard in itself. Electric pumps must be connected to the emergency power supply. Propane-powered fire pump motors are a serious fire hazard due to the presence of propane gas. Propane-powered motors should be removed from service and replaced with either diesel or electric motors.
- Assess the fire pump for compliance with NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps." Check for the presence and condition of overloads and disconnects, recirculation relief, approved controllers, motor, and impeller. The fire pump should also be equipped with a bypass to permit water flow around the pump in the event that the pump fails.
- If a fire pump is installed, does it have a permanent connection to drain to permit testing? Has the pump been inspected and tested on a regular basis? Diesel pumps should have been test run on a weekly basis, and electric fire pumps should have been test run on a monthly basis. The pump discharge characteristics should have been tested on an annual basis.
- CO_2 systems are a life safety hazard. To reduce the life safety risk, these systems should be equipped with pre-discharge warning alarms and the capability to disable the system to permit personnel to work on the system or in the generator enclosure.
- For CO_2 systems, are rescue procedures in place for occasions when personnel are working in the protected space? Is self-contained breathing apparatus available for rescue and re-entry after a discharge? Is portable air-monitoring equipment available to allow personnel to check that the space is safe for re-entry?
- For CO_2 systems, is the system capable of discharging a sufficient amount of gas to protect the volume of the enclosure? NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume, and this figure does not include the amount required for extended discharge during generator rundown.
- Are there an adequate number of discharge nozzles for the CO_2 system?

- What is the condition of the CO_2 storage vessels, piping, and nozzles? For a high-pressure system, are the storage cylinders overdue for hydrostatic testing? For a low-pressure system, what is the condition of the tank and refrigeration system? Is the low-pressure storage tank equipped with a relief vent valve to discharge excess pressure to the atmosphere? Are the piping and fittings made of the correct material as specified by NFPA? Are the fittings and piping able to handle the burst pressure as specified by NFPA?
- A generator protected with a CO_2 system must be enclosed to prevent loss of agent and reduction of effectiveness. It will generally not be possible to completely prevent leakage, but large openings and holes in the enclosure should be noted.

4. Enclosures

Older hydroelectric stations and smaller stations tend to have units located in an open floor area. Newer stations generally have units enclosed within solid walls, which act as a barrier to the spread of smoke and fire.

Enclosures can be made to provide a barrier to smoke and fire by the construction as a fire separation, the provision of a fire-resistance rating, the installation of fire stop systems having a fire protection rating for service penetrations, and the use of closures (including fire doors and fire dampers) having a fire protection rating for doors openings and vent passages. Enclosures are intended to complement, not replace, automatic fire suppression systems.

An assembly constructed as a fire separation has no unprotected openings, and it is smoke-tight. To maintain the smoke-tight feature of the assembly, fire stop systems and closures should be used where possible, but due to the operational features of a generator, it might not be practical to make the enclosure completely smoke-tight.

An assembly built with a fire-resistance rating means that the assembly is of a construction that, under specified test and performance conditions, has exhibited the ability to withstand the passage of flame and the transmission of heat for a certain duration of time. It should be determined if the enclosure has a fire-resistance rating and what that rating is. A minimum two-hour fire-resistance rating is recommended.

Doors and access hatches should be equipped with closures having a minimum 1.5 hour fire protection rating. Fire stop systems for cables, cable trays, conduits, ducts, pipes, tubing, and other services should have a minimum 1.5 hour “F” rating from a recognized testing agency.

If in an existing hydro plant, it is not possible to retrofit fire compartments around a generator, then automatic fire suppression is critical.

When performing a condition assessment of a generator enclosure, the following points should be considered:

- Is there an enclosure? What was the design intent of the enclosure? What is the current condition of the enclosure?
- To what degree can the enclosure contain an explosion, fire, and smoke?

- What type of construction is the enclosure? Is the enclosure relatively smoke-tight? Does the enclosure have a fire-resistance rating?
- Are service and cable penetrations equipped with fire stop systems having a fire protection rating? Are the fire stop systems in good condition (that is, look for chipping, cracking, and brittleness)?
- Are doors, air vent passages, and other openings equipped with door or fire dampers with a fire protection rating? How are the dampers operated, that is, are they connected to the unit fire alarm control panel or station fire alarm panel or do they use a simple heat-activated fusible link?
- Is there asbestos present in the generator enclosure? Asbestos is a serious health hazard.

5. Smoke Control

A generator fire will produce large amounts of smoke due to the large quantity of combustible insulation on the windings. The systems described in this section reduce the amount of smoke generated and transmitted into other parts of the powerhouse; however, even these measures will likely not be sufficient to completely eliminate smoke contamination.

Many of the older hydroelectric power stations in North America were constructed with limited ventilation and no means of smoke control. Low concentrations of smoke can injure, incapacitate, and cause death, and therefore, smoke control is an important aspect of fire protection. Smoke control systems are custom designed for the specific application, and therefore, only general principles are considered in this guide.

NFPA 90A, "Standard for Air Conditioning and Ventilating Systems," NFPA 204M, "Guide for Smoke and Heat Venting," and NFPA 92A, "Recommended Practice for Smoke Control Systems" are publications that contain useful design information, but it might be difficult to meet the literal requirements of these documents in an existing hydroelectric generating station.

When performing a condition assessment of smoke control in an existing hydroelectric station, the following points should be considered:

- Is there any smoke control or means of ventilation? If so, what was original design? Was the original design concept sound? What is the current condition of the system?
- To vent smoke, the affected area must be pressurized with fresh air, and contaminated air must be extracted. Due to the buoyant nature of hot gases, air extraction is best performed at the ceiling of the affected space.
- Smoke control is of particular concern in underground power stations.
- Smoke control should have the capability of both manual operation and automatic operation by the fire alarm panel.
- The condition of fans, wiring, and controls should be checked. Fans used for smoke removal often need to be specially selected to handle high temperatures, and heat-resistant cable might be required.
- Could the power supply for smoke control be interrupted by a fire? Is there a provision for emergency power supply?

4.5.2.17 Braking System

The brakes are vital to the protection of the generator bearings, particularly in large umbrella-type units. When the rotor is spinning at or near normal operating speeds, the thrust bearing basically rides or "planes" on a film of oil. Operation below the critical speed will result in the breakdown of the oil film and consequent bearing surface-to-surface contact or "wipe." When the unit is being shut down, the brakes must be effectively applied at the appropriate time, to ensure the rotor is stopped quickly to avoid prolonged slow speed operation when planing does not occur resulting in a "wiped" bearing. In addition, when the unit is shut down, the brakes must hold the rotor stationary to avoid creep that could also result in wiping the bearing. Creep is a slow rotation of the rotor due to leakage past the gates.

The braking system, including the hydraulics, should be carefully inspected and overhauled, if necessary, to ensure reliable operation and avoid damage to the generator.

Provisions for the capture of brake pad dust may be installed, and this system should be checked for proper functioning.

Asbestos brake pads should be replaced (using appropriate cleanup procedures).

Ensure that the brake application speed is correct.

Criteria:

Leaks in the hydraulic system, wrong brake application speeds, and the presence of asbestos brake pads are unacceptable.

4.6 Assessment of Remaining Life

Table 4-1

Equipment Data and Technical Information		History of Maintenance and Major Repairs
Performance and Operational Information		Condition Assessment of Equipment
Risk Evaluation		**Assessment of Remaining Life (Step 4-8, Volume 1)**
Condition Rating (if available)	Repairability Rating	Environmental Issues
Possible Life Extension Activities		Timing and Costs of Life Extension Activities

4.6.1 Introduction

The estimation of remaining life is the most subjective element of the condition assessment. The overall objective is to replace, rehabilitate, or upgrade equipment at the optimum point in the equipment's life cycle. The scheduling of these activities requires that the approximate year of equipment failure is predicted. Such predictions should be made by an experienced engineer who has access to industry statistics on the service life of equipment for certain service conditions.

Optimum time in this context means the time beyond which the impacts of **not** intervening will be greater in the long run than the impacts of intervening now. In terms of risk cost, this is the time when the risk costs are minimized. Risk costs include the costs of equipment replacement and the consequences of equipment failure (such as lost energy, collateral damage, cost increases for purchase, or installation of new equipment due to working in an "unplanned" outage situation).

Under the auspices of the CEA, a consortium of energy companies from Canada, the United States, and abroad have undertaken "remaining life" studies for hydro power equipment. The results of this project have been used to develop optimal equipment replacement strategies and computer software tools to assist with the prediction of remaining life and scheduling of equipment replacement. All costs associated with equipment replacement decisions are included in the methodology used to arrive at optimal timing for the equipment replacement.

Table 4-6 lists typical life expectancies for the major electrical equipment covered by this volume. This information, combined with the condition and performance assessment, can assist the engineer in determining an approximate remaining life for each piece of equipment.

Useful life means the equipment is capable of sustaining the design transient stresses. For generators, this includes such events as voltage transients due to switching, for example, and current surges due to system ground faults or short circuits. When the useful life has been exceeded, these transient stresses can result in the failure of the component.

The concept of "remaining service life" is not always easy to apply to mechanical and electrical equipment. Certain equipment can be maintained indefinitely as long as parts for repair are available or repairs can be made. In addition, some equipment can be repaired easily and brought back to original condition and performance level without a major rehabilitation project. The equipment's "useful life" can then be quite different from its service life. Although the service life can be extremely long, there are issues that would limit the equipment's useful life, including:

- Increasing maintenance costs to keep equipment in service
- Increasing equipment unreliability and outage time associated with the increased maintenance requirements
- Increasing obsolescence of parts necessitating the costly manufacture of parts
- Maintenance problems associated with equipment of a hybrid structure after too many repairs and substitute parts have been installed to keep the equipment operational
- Deteriorating equipment condition and performance to an extent that it cannot be repaired or rehabilitated to its original condition even though the equipment is still largely operational and can stay in service
- A change in operational conditions can mean that a piece of equipment is unable to meet the new requirements of the plant even though it is in relatively good condition

Frequently, equipment condition is not the driver for replacement and remaining service life is not a factor in the replacement decision. The real driver of equipment rehabilitation or replacement is the upgrade opportunity for increased performance (that is, plant or system revenue) through increased power and efficiency. Sometimes, the opportunity to supply additional plant products such as peaking capability to capture high electricity rate periods or voltage support is the driver for equipment replacement.

A note should be made in the Equipment Condition Summary worksheet (see Chapter 4.1) when "useful life" is the issue driving equipment replacement rather than "remaining service life."

4.6.2 Reliability and Outage Statistics

The CEA has been collecting reliability and outage statistics for electrical generation, transmission, and distribution equipment since 1975. The CEA's Consultative Committee on Outage Statistics provides a comprehensive database of component and system reliability and performance data, which it analyses and reports in its Generator Equipment Status annual report. These annual reports provide information that can assist with the prediction of remaining life of plant assets based on statistical trends for more than 747 hydraulic units installed in Canada. The database is limited to hydraulic units that are more than 5 MW.

In Canada, the average age of hydraulic units is 43 years. The average operating factor for hydro units in 1999 was 72.95%. The average gross maximum electrical output (as per the unit rating and confirmed by acceptance tests) is 84.8 MW.

From this database of units, some interesting statistics have been reported. Of the top five causes of forced outages for the five-year period 1995–1999, "generator and auxiliaries" is reported as the Number Two cause of outages, and excitation systems are reported as the Number Three cause (transmission limitations are the Number One cause). The method of reporting forced outages at plants can have an effect on these statistics.

A further look at five years of data (1995–1999) shows some other unique trends concerning hydro units. In the 1999 annual report, the graph of incapability factor versus unit age is virtually flat oscillating between 8 and 10% regardless of how old the plant is. Similarly, the graphs of failure rate versus unit age and mean forced outage duration versus age are flat. These statistics suggest that age alone does not influence the reliability of generating units and that condition is more a function of application and maintenance practices rather than just the inevitable deterioration of equipment with age.

A breakdown of the five-year statistics shows that of the major components that contribute to plant incapability (external causes excluded), the generator accounts for 37% of the total. Table 6-6 in the 1999 annual report provides a summary of the breakdown of the generator components and their contribution to incapability factor, number of forced, maintenance and planned outages, and scheduled unit de-ratings.

4.6.3 Generator

4.6.3.1 General

Life extension of the generator will depend on the owner's intended use and loading. Conservative loading, nameplate or less, and infrequent loading cycles—particularly start/stops—will increase the likelihood of extending the life well beyond the 35 to 50 years estimate. However, economics and market opportunity are just as likely to lead to overloading, both short term and long term, leading to accelerated aging of stator winding, rotor winding, and cable insulation due to overtemperature. The owner can probably, with expert consultation, achieve some overload profiles with minimum cost of life. For instance, operating at 1.05 pu voltage, or greater, with verification testing, may achieve substantial economic benefits for a relatively insignificant cost. Prudence is advised.

4.6.3.2 Generator Age

The actual age of the generator (in calendar years) can provide a first indication for the need to modernize, as shown in Chapter 3, "Screening." However, the on-line hours are more significant, and the equivalent running hours (ERH) are the best indicator of the need to modernize. These also take into account the number of start/stop sequences that contribute to stress and aging of generator components. The following formula is recommended by the German Association of Electric Power Producers:

$$ERH = OLH + (10 \times NST) \qquad \textbf{Eq. 4-1}$$

where:

ERH = on-line hours (OLH) plus 10 times the number of start/stops (NST)

In large, modern plants, on-line hours and start/stops are often automatically recorded; in older plants, this data must be retrieved from plant logs or estimated from operators' experience when written data are not available. Because the ERH provides only a rough indication, reasonable estimates are sufficient. The resulting ERH can then be used to predict the remaining life of generator components using the tables and text in the following subsection.

4.6.3.3 Generator Stator Windings

A long-established rule of thumb is that generator windings have a useful life of 30–40 years. Many owners of older hydroelectric units find it economically attractive to rehabilitate their generators with the intent of obtaining at least 20 and sometimes 40 or more years of life from the equipment.

There are some generally accepted estimates of typical service lives for different types of stator windings. Table 4-6 provides a summary.

Table 4-6
Life Expectancy

Insulation Type	Expected Winding Life
Thermoplastic	(350,000–500,000 ERHs) 30–45 years
Thermosetting - early polyester	(250,000–400,000 ERHs) 20–35 years
Thermosetting - modern epoxy	(350,000–500,000 ERHs) 30–45 years

"Early polyester" windings were widely installed in the early 1960s. Many of them were replaced in the early- and mid-1990s due to poor condition and failure after 30 years of service.

4.6.3.4 Generator Field Windings and Poles

Unlike stator windings, field windings and poles are not usually subjected to an anticipated end-of-service life analysis. They are usually replaced or re-insulated at the same time as the stator windings if their condition is poor.

4.6.4 Excitation Systems

Exciter windings also slowly degenerate with age but are rarely subject to end-of-life studies. They are usually replaced when maintenance becomes excessive, there are problems with the AVR or protection and control equipment, or the exciter does not have enough increased capacity to support an upgraded generator.

4.6.5 Generator Thrust Bearings

The expected life of thrust bearings is greater than 40 years barring any bearing wipes. Thrust bearing wipes are usually due to the following:

- Improper adjustment
- Oil contamination (cooler leaks)
- Oil lift pump failure
- Low oil level
- Restarting before OEM-specified cooling period
- Creeping due to wicket gate or nozzle leakage

Some service will probably be required on the bearing babbitt after 10–15 years of service.

4.6.6 Circuit Breakers

The two main factors that affect circuit breaker life expectancy are environment and loading cycles. A generator circuit breaker is rarely closed or tripped on full load, and if its environment is clean, service life can easily exceed 60 years. The life of mechanical circuit breakers does not usually exceed 50 years. The problem of obsolescence and the difficulty in obtaining spare parts that result in high maintenance costs can often necessitate breaker replacement. On the other hand, paper-insulated porcelain bushings deteriorate. Typical service life of breaker bushings can also exceed 60 years and depends on factors such as environment, mechanical damage, and deterioration due to voltage or current transients.

4.6.7 Generator Cables and Buses

Although insulation failure is usually the final breakdown mode in cables, it is rarely the primary cause. For example, polyethylene cables, which are made without defects, operated within temperature limits, and are kept dry, could last 40 years or more. PILC cables that have not suffered mechanical or corrosion damage have often outlived their designers. Laboratory testing may be one life extension activity recommended to further assess the condition of suspect cables.

Laboratory assessment may be recommended after a failure has occurred. Lab assessment is made to determine whether cables of similar type and age should remain in service. Lab assessment may consist of dissection, water tree counts, and various small sample, chemical tests. If longer samples can be taken, ac breakdown tests are performed. Laboratory tests tell the most accurate story of cable condition and cause of failure, but only on the sample examined. To understand the state of the insulation of the existing cable, on-site condition assessment is needed.

If a long sample can be removed from a cable installation, an ac breakdown test will give a good indication of the condition of the sample. On new 15 kV cable, ac breakdown may occur at over 150 kV. As the cable ages, the breakdown strength decreases. Cables nearing end of life will breakdown at or below three times the operating voltage. For a 15 kV cable, this will be 25 kV or less line-to-ground.

4.6.8 Generator Cooling

The service life of generator coolers depends greatly on the water quality and its corrosive characteristics. Therefore, typical life is difficult to assess. Re-tubing of coolers may be required every 20 years when clean water is used, but water velocities are also a factor. The typical life of an air cooler is 35 years.

4.6.9 Generator Fine Protection

Fire protection systems are not subject to end-of-life studies; rather, components are replaced due to damage or obsolescence.

4.7 Life Extension Activities

Table 4-1

Equipment Data and Technical Information	History of Maintenance and Major Repairs	
Performance and Operational Information	Condition Assessment of Equipment	
Risk Evaluation	Assessment of Remaining Life	
Condition Rating (if available)	Repairability Rating	Environmental Issues
Possible Life Extension Activities (Step 4-5, Volume 1)	Timing and Costs of Life Extension Activities	

4.7.1 Introduction

The scope of hydroelectrical and mechanical projects for an LEM plan range from the rehabilitation of one or more components such as the generator stator winding or excitation system to a complete generator replacement. Table 4-3 of this chapter provides a list of common life extension activities for each type of equipment.

The decision to rehabilitate or replace a piece of equipment has an effect on the scheduling of other life extension activities. For example, if the decision is made to replace a piece of equipment in five years, then other typical life extension activities such as painting may be reduced in scope or eliminated altogether from the LEM plan in the preceding years.

In general, major generator rehabilitation should not be required until after approximately 40 years of operation; however, this varies considerably from unit to unit. Some units require disassembly and major rehabilitation/repair after 10–20 years, while others have operated for more than 50 years without major rehabilitation. The frequency of rehabilitation depends on the generator design, the method of operation, and the general maintenance program for the equipment. Generator operation would generally be considered unsatisfactory if dismantling for generator rehabilitation is required more frequently than every 20 years.

4.7.2 Generator

4.7.2.1 Generator Externals

Life extension activities include:

- Clean and paint all ferrous surfaces
- Check/repair causes of erosion or contamination

4.7.2.2 Generator Accessories (General)

Life extension activities include:

- Thoroughly clean all surfaces of oil and dirt, using dry ice pellets, solvents, and grit blasting
- Repair oil seals on bearing pots and shafts
- Consider the installation of low-vacuum or vapour collection systems
- Apply protective coatings as appropriate, that is, paint ferrous and concrete surfaces

4.7.2.3 Stator Frame

Life extension activities include:

- Repair any weld fractures, including keybars
- Retorque frame and anchor bolts
- For expanding frames, recenter and relubricate sliding surfaces
- Clean and paint ferrous surfaces

4.7.2.4 Stator Core

Life extension activities include:

- Repair any core lamination defects.
- Restore interlaminater insulation in rubbed areas using phosphoric acid etching and/or local grinding.
- Retorque core and flange bolts.
- If wedging and winding are satisfactory, clean and paint all core surfaces with insulating protective coating such as penetrating epoxy spray. However, the use of traditional clear, red, black, or white is not recommended, because these may mask a defect or corrosion products' hampering future inspections. A light blue or green color is recommended.

4.7.2.5 Stator Winding

Life extension activities include:

- Thoroughly clean all end turn and circuit ring surfaces.
- Repair any previous groundwall failures by replacing bars or coils.
- Repair gradient paint system.
- Consider reversing the winding if PD tests or coil/bar sections indicate internal discharge.

- Consider rewedging options and replace or repair side packing.
- Remove insulation on exposed joints (if suspect) and repair as necessary. Rewedging was formerly required every 20 years, but with the harder insulation materials now used and the use of Kempel-type fiber ripple springs behind the wedge, rewedging is seldom required now.
- Paint all exposed winding, rings, and insulation support structures with a light blue or green insulating spray coat (not red, black, or white).

4.7.2.6 Rotor

Life extension activities include:

- Thoroughly clean all exposed surfaces on the pad pieces. Do not use excessive amounts of liquid solvents because carbon can be carried into difficult to clean crevices resulting in poor meggar readings. Repaint the winding surfaces.
- The turn insulation should be replaced if it is in poor condition as evidenced by very low insulation resistance readings that do not respond to cleaning.

4.7.3 Excitation System

Life extension activities for the excitation system include the following for a rotary exciter:

- Undercut and align brushes
- Replace the AVR
- Stone the commutator
- Center the commutator
- Replace adjustable tension brushholders with constant pressure type

4.7.4 Generator Bearings

If thrust runner machining is required, it is critical that the thrust runner surface be machined carefully so that the runner surface is perfectly perpendicular to the shaft. Tolerances for thrust runners are usually in the 0.001 inches (0.025 mm) range. When a two-piece runner is used, the joint must be “perfect.”

Lubricating oil should be removed and guide bearing journals and bearing pads inspected, noting as-found clearances. Defective pads should be rebabbitted or replaced. Installation of thrust and guide bearing metal thermocouples or RTDs should be considered. The cooling system should be tested for leakage. Lubricant high/low level detectors should be installed for remote monitoring. Replacement of lubricating oil with modified viscosity oil should be considered.

If thrust bearings need to be rebabbitted, the thrust bearing shoes must be cast and machined. Ultrasonic testing should be performed to verify the integrity of the babbitt-to-steel bond and the absence of porosity. A babbitt-to-steel bond of not less that 85% should be specified.

Other life extension options include:

- Purchase additional spare parts: complete set of thrust pads, a thrust runner, and a guide bearing
- Total replacement of thrust bearing (very rare)
- Replace life pump system: ac and dc pumps
- Install external coolers for ease of maintenance
- Replace babbitt thrust bearing with PTFE with or without an oil lift system

The use of oil mist/vapor removal systems has been plagued with problems. Most systems are custom-built for a particular unit, but the designs usually involve a system of encapsulating the shaft and then conducting the oil mist via ductwork to an external location where the oil is condensed. However, leaking ductwork and other problems then lead to system dismantling.

4.7.5 Circuit Breaker

Life extension activities include:

- Overhaul the breaker as indicated by the test and inspection program carried out during the condition assessment
- Replace any defective or deteriorated bushings
- Add remote control (capability upgrade)
- Consider replacing an older breaker for which it is difficult to obtain spare parts

4.7.6 Generator Terminal Equipment

Life extension activities include:

- Replace neutral and/or live current transformers, disconnect switches, and resister bank
- Replace potential transformers and surge protection

4.7.7 Low-Voltage Cables and Buses

If the neutral or shield is corroded at many points along the length of the cable, a recommendation to replace the entire cable may be made. If the corrosion is isolated to only a few points, these locations may be cut out and new sections of cable spliced in place. This technique may save the cost of entire cable replacement and provide confidence that the remaining cable neutral or shield is in good condition and the cable is unlikely to fail suddenly.

4.7.8 Generator Cooling System

The life extension activities include:

- Repair generator coolers (re-tubing)
- Install new generator coolers
- Repair supply piping and accessories
- Install new generator supply piping, pressure reducing valves, and strainers

Primary life extension activities for the cooling water supply consist of replacement or rebuilding of pumps, strainers, and other equipment.

Strainer rebuilding typically includes replacement of the straining media. Brass straining media can be replaced with stronger stainless steel materials. Self-cleaning filters should be considered when replacement is required.

Large valves may be rebuilt, including replacement of seats, seals, and stems. Replacement of smaller valves is usually more cost-effective. Gate valves larger than approximately 12 inches (30.48 cm) are quite costly; and when replacement is necessary, it might be possible to substitute a butterfly valve or a knife gate valve.

Piping should be replaced if it is badly corroded. New stainless steel piping can be considered for corrosive environments. Plastic and high-density polyethylene pipe has also been used for some applications, although care must be taken to ensure that the softer and less rigid polyethylene pipe is protected from external damage and that it is well supported to prevent sagging sections between supports.

If water contamination is severe and has resulted in plugging or erosion of coolers or load limitations, it may be necessary to modify the cooling water system. Proven remedies are closed-cycle systems with heat exchanger coils in the turbine intake or forebay and double-circuit systems.

Heat exchangers should be flushed/cleaned and retubed if leaking. If only a few tubes leak, then these tubes can be plugged.

Anti-sweat insulation should be replaced if deteriorated; however, replacement of asbestos insulation can be costly. Nevertheless, deteriorated asbestos insulation must be removed for health reasons.

Application of a new protective coating to piping, valves, and equipment will also aid in life extension.

Control devices are either rebuilt or replaced if they do not function satisfactorily.

Automation requires that hand-operated valves be replaced by power (electric or pneumatic) operated valves if the open and close operations of the valve are a part of the unit start/stop

sequence. One temperature sensor and one pressure sensor should be installed at the cooling water intake, after the pumps, and at the cooling water discharge. For larger, water-cooled generators, temperature and pressure sensors should also be installed at both ends of each generator cooling water loop.

4.7.9 Generator Fire Protection

4.7.9.1 General

The aim of life extension for generator fire protection should be to maintain or slightly improve the level of fire protection available. The options for life extension will depend on the type and condition of the existing fire protection systems.

When considering life extension measures, it is important to be mindful of:

- The design objectives of the existing systems
- The condition of the existing systems
- Modifications to the existing systems that have been made since initial installation
- Items that can restore or improve the intended level of protection
- Upgrades that can extend the life of the existing system

Life extension upgrades are generally of a lower cost than a full modernization. Life extension should be considered in the following scenarios:

- The existing fire protection is acceptable
- The value of the station is relatively low
- The station has a low annual energy production
- It is expected that the station will be decommissioned or redeveloped within the next 10 years
- A combination of these factors

For stations with limited fire protection, high value, large energy production, or a considerable life span remaining, it might be more cost-effective to modernize the generator fire protection systems.

4.7.9.2 Fire Detection and Alarm Signaling

Due to the primary importance of this system, a life extension program should not overlook fire detection and alarm signaling.

Basic life extension for these systems involves testing, maintenance, replacing outdated components, and replacing damaged components.

In addition, the following measures can be considered for life extension of an existing system:

- If there is a lack of fire detection coverage for the generator, and if the budget permits, install additional fire detection devices.
- If ambient noise prevents audible alarms from being heard, the volume might need to be increased, or additional audible alarm signaling should be considered. Conversely, the sound level of devices in offices and control rooms is often set too loud and could disrupt operations during an emergency. Volume in these areas could be adjusted down. This measure is not directly related to generator fire protection, but there is a need to have effective alarm signaling in all areas of the station.
- If the ambient sound frequency cancels the sound from a fire bell, replacement of fire bells with horns should be considered. Horns produce an audible signal of varying frequency, and therefore, their signal will be outside of the cancellation range at least some of the time.
- Review the need for additional visual devices especially in areas with high sound levels or other audibility problems. Ensure that visual devices are visible in all areas (for example, unit control boards can often block the visual signal to certain areas of the generator floor).
- Does the unit fire alarm control panel have automatic control of the fire suppression system? If so, what combination of detectors or protection and control signals is needed to activate the suppression? Can the combination be modified or expanded to give a better response?
- Can the fire alarm panel open the circuit breakers to disconnect the generator from the power system if the fire suppression is activated?
- Does the unit fire alarm control panel have automatic control of the HVAC system through the main fire alarm panel? If so, could the system be improved to give improved smoke control?
- Would the fire alarm panel benefit from enclosure in a cabinet built for industrial use? Some of the commercial cabinets were intended for use in office or apartment buildings and might not provide proper protection for the fire alarm circuitry.
- Consider bracing the unit fire alarm control to resist seismic movement.
- Consider off-site monitoring if the station fire alarm system has this capability. Remote monitoring is an important consideration for stations that are unattended for periods of time. Remote monitoring can also allow a utility to formulate a quicker response to an emergency situation by automatically informing an outside control center of an emergency.

4.7.9.3 Fixed Fire Suppression

Life extension of fire suppression systems involves maintaining and improving the operation and safety of existing systems. Water-based systems and CO_2 systems are the most common systems in use.

Water-based systems have demonstrated their effectiveness in extinguishing generator fires. Experience has shown that the water damage resulting from deluging a unit with epoxy-based insulation is minimal. Water systems have proven to be reliable; and at hydro plants, they have the advantage of a virtually unlimited supply of extinguishing agent.

CO_2 systems are acceptable for existing installations, but there is a life safety hazard and a concern with the effectiveness of these systems. Existing systems should be reviewed to ensure that protective measures are in place to reduce the risk of exposure to personnel.

When considering options for life extension of a fire suppression system, the following should be considered:

- Perform testing, inspection, and maintenance on a regular basis.
- Replace all damaged or corroded components.
- Can the system be better interconnected with the fire alarm system? Can the fire alarm system handle additional duties? For example, the fire alarm panel could be made to supervise water leakage past a deluge valve.
- Could automatic or manual activation capability be added at a reasonable cost? Can the manual activation be better identified or moved to a more conspicuous location? An option for life extension is to install features to avoid accidental manual operation. For example, a sliding lock could be added to a quarter-turn valve handle.
- Equip all systems with a disabling feature to prevent undesired discharge during maintenance.
- Provide seismic restraint for existing fire protection piping and valves.
- Install bonding and grounding of fire protection piping to prevent the creation of voltage potential and an electrocution hazard.
- If a water-based system was installed, check that all components are listed by a recognized testing agency for use in a fire suppression system.
- Some of the older-style deluge valves used a complex pneumatic detection and activation system. Consider replacing problematic older-style deluge detection and valves with simpler components.
- For a water-based system, flush fire protection piping. If water is especially dirty or contains scale, the pipe might be in poor condition and might require replacement.
- If it can be achieved at an acceptable cost, additional water-spray nozzles should be added if the current design does not provide adequate coverage or applied density.
- Some of the older-style water deluge systems incorporated a compressed air line for the purpose of breaking up the water spray into smaller drops. Due to problems that can be caused by a pressure imbalance between the water and the air, consider removing these compressed air lines.
- If a water-based system is installed, a test loop piped directly to drain will facilitate testing.
- If a water-based system is installed, review the water supply. If valves do not have supervision, consider adding this feature. Fire protection water supply should not be affected by shutoff of domestic water or other service water supply. Maintain pressure-reducing valves and other components so that they do not impair the ability of the system to provide required flow and pressure.

- If the station has low water pressure, consider improvements to get the most out of the existing system. For example, undersized or inefficient fittings can cause significant pressure losses.
- Is there is an existing fire pump? Ideally, the pump and motor should be listed by a recognized testing agency as being suitable for use as a fire pump, but if they are not, these components do not necessarily need replacement; however, they should be maintained in good condition. An exception is the use of propane-powered fire pumps. Propane-powered motors and propane storage are serious fire hazards and should be replaced by diesel or electric motors.
- If a fire pump is installed, ensure that the packing glands are set at the proper tightness. If the glands are too tight, the pump can overheat. An occasional drip of water coming from the packing glands when the pump is cool generally indicates proper tightness.
- Has the fire pump been inspected and tested on a regular basis? Diesel fire pumps should be test run on a weekly basis, and electric fire pumps should be test run on a monthly basis. Check the pump discharge characteristics on an annual basis to ensure that the pump can provide the required flow.
- CO_2 systems present a life safety hazard and are not recommended for new installation, but existing systems are still common in industry. Maintain existing life protection features. Rescue procedures should be in place for when personnel are working in the protected space, and self-contained breathing apparatus should be available. In the event of a discharge, air-monitoring equipment and self-contained breathing apparatus should be available to allow personnel to check that the space is safe for re-entry.
- CO_2 systems should be equipped with pre-discharge warning alarms and the capability to disable the system so that personnel can work on the system or in the generator enclosure.
- Consider the addition of an abort switch for manual shutdown if a CO_2 system is not equipped with this feature.
- For CO_2 systems, is the system capable of discharging a sufficient amount of gas to protect the volume of the enclosure? NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume, in addition to the amount required for extended discharge during generator rundown. Life extension of a CO_2 system might necessitate the addition of more CO_2 storage.
- Repair or replace CO_2 storage vessels, piping, and nozzles as needed. For a high-pressure system, perform hydrostatic testing of the storage cylinders. For a low-pressure system, maintain the tank and refrigeration system. A low-pressure storage tank must be equipped with a relief vent valve to discharge excess pressure to the atmosphere.
- Replace piping and fittings that are not made of the correct material as specified by NFPA. Fittings and piping should be able to withstand the burst pressure specified by NFPA
- A generator protected with a CO_2 system must be enclosed to prevent loss of agent and reduction of effectiveness. It will generally not be possible to completely prevent leakage, but large openings and holes in the enclosure should be sealed. If these openings cannot be sealed, then an additional amount of CO_2 gas will be required to offset leakage.

4.7.9.4 Enclosure

An enclosure constructed as a fire separation with a fire-resistance rating around the generator is a method of confining fire and smoke to a limited area. If the generator is not enclosed, there are no options for life extension; however, if an enclosure is provided, there are some items to consider:

- What is the present condition of enclosure? If the enclosure material is cracked, crumbling, or otherwise in need of repair, then it should be remedied.
- Are service and cable penetrations equipped with fire stop systems having a fire protection rating? If existing fire stop systems are chipped, cracked, brittle, or are not a listed fire stop system, then consider replacing them with modern fire stop systems. It might not be possible to fire stop all penetrations.
- Are doors, air vent passages, and other openings equipped with door or fire dampers having a fire protection rating? If not, then consider adding doors or dampers with such a rating. It might not be possible to provide rated closures for all openings.
- Is asbestos present in the generator enclosure? Asbestos is a serious health hazard. Existing asbestos should be removed in an approved manner if air monitoring indicates that is a hazard. If air monitoring indicates that no hazard is present in the air, construction features containing asbestos should be identified and labeled. Modifications to these features should be prohibited. An asbestos identification and management system should be developed and implemented if there is known or suspected asbestos in the station.

4.7.9.5 Smoke Control

Life extension of other fire protection features have an improvement on smoke control by reducing the amount of smoke generated by a fire.

Many of the older hydroelectric power stations in North America were constructed with limited ventilation and with no means of smoke control, and therefore, their options for life extension might be limited in these stations.

When weighing options for life extension of the smoke control and ventilation system, the following important points should be kept in mind:

- Is there any smoke control or means of ventilation? If no smoke control is installed and there is only a limited air-handling system, there might not be any options for life extension.
- If there is an existing building ventilation system, the design of the system could be reviewed and adjusted to at least minimize the spread of smoke through the building.
- Smoke control is of particular concern in underground power stations.
- If there is a smoke control system, or if the ventilation system can be configured to reduce the spread of smoke, consider adding either automatic and manual operation.
- Check the condition of fans, wiring, and controls. Fans used for smoke removal often need to be specially selected to handle high temperatures, and heat-resistant cable might be required. Older, low-efficiency fans could be replaced with newer, high-efficiency models. Conventional cable could be replaced with heat-resistant cable.

4.7.10 Braking System

Life extension options for the braking system include:

- Replace the brake hydraulic system
- Replace asbestos-type pads with more environmentally friendly types (for example, fiberglass)
- Change brake application speed to reduce wear and prolong pad life

4.8 Timing, Schedule, and Costs of Activities

Equipment Data and Technical Information		History of Maintenance and Major Repairs
Performance and Operational Information		Condition Assessment of Equipment
Risk Evaluation		Assessment of Remaining Life
Condition Rating(if available)	Repairability Rating	Environmental Issues
Possible Life Extension Activities		**Timing and Costs of Life Extension Activities (Step 4-8, Volume 1)**

4.8.1 Assigning Activities

The condition assessment should provide the early framework for an LEM plan. Equipment maintenance, rehabilitation, and replacement activities have been identified and now need to be organized into a 20-year (or other horizon) plan. Before specific activities can be assigned to a particular year in the LEM plan, certain policies and guidelines on the assignment of activities must be established. The following are some of the questions that must be answered:

- Is the general philosophy concerning LEM opportunities one of consolidation (that is, trying to do as much work as possible during an annual shutdown)? This would be the philosophy if lost revenue due to shutdowns was high and overshadowed the capital requirements for the actual work.
- Are there limits on the capital available in any one year? This may limit the scope of work for a particular year even though there would be benefits to combining work activities instead of completing them over several years.
- Is there a preference in maintaining a constant level of annual expenditure and staffing (that is, spreading out LEM activities to avoid years of very high capital requirements and to level out staffing requirements)?

Once these questions have been answered, the LEM activities can be scheduled over the required planning horizon on both technical and financial factors.

Probabilistic models have been developed to assist with determining optimal timing of equipment replacement before failure. These can be quite complex and are only valuable if sufficient data are available to populate the model.

4.8.2 Major Unit Overhauls

An evaluation of the existing levels of maintenance and whether or not they are adequate must be made. Major overhauls or rehabilitation projects are usually required at regular intervals. An optimal schedule of unit overhauls must be established and the associated costs inserted directly into the LEM plan.

4.8.3 Equipment Lead Times

Equipment lead time for large, complex, or project-specific equipment that has a long order time is an important factor in scheduling activities for the LEM plan.

Chapter 6 of this volume describes estimates of design, manufacture, delivery, and installation times for some critical electromechanical equipment.

4.8.4 Assigning Costs

Chapter 6 provides information on the costs and benefits of life extension activities.

4.9 Environmental Issues

<table>
<tr><td colspan="2">Equipment Data and Technical Information</td><td colspan="2">History of Maintenance and Major Repairs</td></tr>
<tr><td colspan="2">Performance and Operational Information</td><td colspan="2">Condition Assessment of Equipment</td></tr>
<tr><td colspan="2">Risk Evaluation</td><td colspan="2">Assessment of Remaining Life</td></tr>
<tr><td>Condition Rating(if available)</td><td>Repairability Rating</td><td colspan="2">Environmental Issues (Step 4-6, Volume 1)</td></tr>
<tr><td colspan="2">Possible Life Extension Activities</td><td colspan="2">Timing and Costs of Life Extension Activities</td></tr>
</table>

This subsection briefly identifies some of the environmental issues that apply specifically to projects involving the generator and associated equipment. Environmental issues surrounding hydro plant projects can be very complex, and a detailed explanation of all hydro plant environmental impacts is beyond the scope of these guidelines.

The information in this subsection is organized so that the following can be identified for the plant electromechanical equipment:

- Project activities that can have an environmental impact
- The LEM projects that can be implemented to manage the environmental issues associated with electromechanical equipment

This subsection does not cover impacts associated with construction activities during implementation of the project. Guidelines on management of environmental considerations during implementation are provided in Chapter 8.

The International Organization for Standardization (ISO) Standard 14000 for implementing effective environmental management systems is an international standard designed for individual companies to set their own environmental goals and commitments to environmental policy. ISO 14000 guides the company to formulate a plan and to carry out a policy to identify significant activities that affect the environment in the production of a good or service. The company then trains personnel in environmental practices and creates an internal audit review system to ensure the program is implemented and maintained.

As highlighted in a 1998 *EPRI Journal* article, worldwide movement or accreditation in all sectors of industry is increasing. The power industry is no exception. The ISO 14000 Information Center reports that 11% of the U.S. companies registered as of June 1998 represent the power/utility sector. The framework of ISO 14000 is a flexible set of criteria, which is aimed at improving the process of environmental management. The criteria encourage setting goals and seeking ways to implement and measure progress towards achieving better environmental performance. Further information on the ISO certification process can be found on the ISO web site: www.iso.ch.

4.9.1 Activities and Environmental Impacts

The following tables list the common activities related to generator equipment that have an environmental impact. These impacts should be considered as part of the overall planning process for LEM projects.

Table 4-7
Project Activities and Environmental Impacts

Activity	Associated Impacts
Generator	
• Removal of lead-based paint	• Contamination of soil, surface water, and ground valves
• Ozone generation	• Air contamination, for example, odor and smoke
• Removal of vapors	• Air contamination, for example, odor and smoke
• Generation and/or disposal of carbon brush dust	• Air contamination, for example, odor and smoke
• Disposal of epoxies, glues, and resins	• Contamination of soil, surface water, and ground water
• Asbestos insulation removal	• Air contamination, for example, odor and smoke • Contamination of soil, surface water, and ground water
• CO_2 cleaning	• Air contamination, for example, odor and smoke
Generator Cooling	
• Generation and/or disposal of asbestos waste	• Air contamination, for example, odor and smoke • Contamination of soil, surface water, and ground water
• Generation and/or disposal of waste filter media	• Contamination of soil, surface water, and ground water
• Spill and/or disposal of fuel, oil, anti-freeze, and grease	• Contamination of soil, surface water, and ground water
Bearings	
• Disposal of epoxies, glues and resins, and oil	• Contamination of soil, surface water, and ground water
• Generation and/or disposal of asbestos waste, solid wastes, and waste filter media	• Contamination of soil, surface water, and ground water
• Generation and/or disposal of metal wastes, oily rags, and paint rags	• Contamination of soil, surface water, and ground water • Disposal in landfill
• Removal of vapors	• Air contamination, for example, odor and smoke
• Pressure washing runoff/sandblasting	• Contamination of soil, surface water, and ground water
• Spill and/or disposal of fuel, oil, grease, mercury, paints, coatings, and detergents	• Contamination of soil, surface water, and ground water
Excitation System	
• Disposal of epoxies, glues, and resins	• Contamination of soil, surface water, and ground water
• Generation and/or disposal of asbestos waste, solid wastes, and waste filter media	• Contamination of soil, surface water, and ground water
• Generation and/or disposal of metal wastes, oily rags, and paint rags	• Contamination of soil, surface water, and ground water • Disposal in landfill

Table 4-7 (cont.)
Project Activities and Environmental Impacts

Activity	Associated Impacts
Braking System	
• Generation and/or disposal of brake dust	• Air contamination, for example, odor and smoke • Contamination of soil
• Generation and/or disposal of metal wastes and solid wastes	• Landfill depletion
• Generation and/or disposal of oil rags	• Contamination of soil, surface water, and ground water
• Spill and/or disposal of fuel, oil, and grease	• Contamination of soil, surface water, and ground water
• Generation and/or disposal of asbestos waste	• Air contamination, for example, odor and smoke • Contamination of soil, surface water, and ground water
Compressed Gas Insulated Circuit Breakers	
• Escape of SF_6	• Air contamination, for example, odor and smoke • Contamination of soil, surface water, and ground water
• Generation and/or disposal of aerosol cans	• Contamination of air and soil
• Generation and/or disposal of desiccants	• Contamination of soil, surface water, and ground water
• Generation and/or disposal of waste filter media	• Contamination of soil, surface water, and ground water
Air Magnetic Circuit Breakers	
Generation and/or disposal of asbestos waste	• Public safety • Air contamination, for example, odor and smoke • Contamination of soil, surface water, and ground water
Spill/disposal of fuel, oil, and grease	• Contamination of soil, surface water, and ground water
Air Blast Circuit Breakers	
• Spill and/or disposal of fuel, oil, and grease	• Contamination of soil, surface water, and ground water
Isolated Phase Bus	
• Runoff from pressure washing	• Contamination of soil, surface water, and ground water
• Spill and/or disposal of paints/coatings	• Contamination of soil, surface water, and ground water

4.9.2 Life Extension/Modernization Projects to Address Environmental Issues

The following subsections provide a brief summary of projects that should be considered for improving environmental compliance at a plant. These projects are concerned specifically with the generator and associated equipment. Chapter 4.3.1 includes information regarding personnel safety.

4.9.2.1 Asbestos Removal

Generators installed before 1975 may contain asbestos as part of the stator insulation system and brake friction pads. Control panels may also be an asbestos composite. Asbestos dust from brake pads may be deposited anywhere in the air circulation system and appropriate cleanup procedures using special vacuums with HEPA filters will be required. Asbestos was used as an armor tape in many thermoplastic systems. Generally handling this armor tape requires gloves, face masks, disposable coveralls and booties, and complete enclosure of the work site. The asbestos in panels is bound, but if new holes are required, personal protection is required. Disposal of removed armor tapes, dust, and waste is regulated. The owner should consider a consultant/contractor specializing and licensed in asbestos handling.

4.9.2.2 Oil Containment

Lubricating oil from generator bearings must be treated as an environmental contaminant. Precautions and collection systems may be necessary to avoid spillage into waterways or drainage. Some older plants may be equipped with oil handling and central storage. The owner may wish to consider independent systems given that oil pot draining and oil treatment is an infrequent activity.

4.9.2.3 Carbon and Brake Dust Collection

Provisions for capture of brush carbon dust and brake pad dust can be effective and will reduce maintenance costs.

4.9.2.4 Ozone Monitoring

Ozone can be produced by PD in the stator winding in sufficient quantities to exceed regulatory limits in any air-cooled generator. In addition to personnel safety, ozone oxidizes organic products in electrical insulation and safety barriers. Regular monitoring of ozone within the generator, the plant, and in office spaces is recommended. Ozone levels depend on unit loading, operating configuration, and relative humidity. Devices have been developed to reduce ozone levels within confined spaces. See Chapter 5.2.2.4 for more detailed technical information.

Ozone is heavier than air and tends to sink to lower levels. Ozone has a low vapor pressure and so tends to stay where it is and not be distributed evenly. It is also unstable and quickly changes back to oxygen.

Factors that contribute to the variability of ozone levels include generator load, voltage, temperature, and ventilation. There is also a large seasonal variation, with the highest ozone levels occurring in the cold dry months of winter. Changes in local atmospheric conditions can also have significant short-term effects. Another factor that may reduce ozone levels in some locations is the presence of other chemical compounds such as solvents or nitrogen oxides (NO_x).

4.9.2.5 Vapor Removal Systems

Labyrinth and felt vapor seals are not always effective in preventing oil mists, resulting in surface contamination of structures, core, and windings. Such contamination attracts dust and dirt accumulation and may reduce cooling. Simple vacuum systems with vapor condenser/collection provisions can be effective. Improved seal design or the use of positive air pressure around the bearings are other alternatives that should be investigated.

4.9.2.6 PILC Cables

Disposing of PILC cables involves draining and disposing of oil. Cutting, bagging, and disposing of the cable must be done using masks, disposable coveralls, and booties.

4.9.2.7 SF_6 Monitoring

SF_6 gas is an environmental contaminant and is regulated in some jurisdictions. If SF_6 gas is used in generator isobars or plant switchgear/breakers, a regular monitoring and locating/repairing program must be undertaken.

5
MODERNIZATION: POTENTIAL FOR IMPROVEMENTS

5.1 Introduction

Volume 3, Chapter 4 outlines a methodology to assess the performance and condition of the generator and its associated equipment and provides input to the life extension portion of the LEM plan. This chapter provides input to the modernization portion of the LEM plan. In addition, it provides information on assessing the upgrade opportunities that are available for electromechanical equipment in order to improve plant performance beyond historical levels.

Figure 5-1 shows the contribution of this chapter to the identification and assessment of modernization opportunities for the LEM plan for the entire plant.

During the condition assessment of the electromechanical equipment, the life extension requirements of equipment are identified. When significant life extension work in the form of rehabilitation or replacement is required, an informed decision must be made concerning whether modernization is warranted (the term *modernization* and its synonyms are defined in Chapter 1). Upgrading of equipment is complex because modernization of one piece of equipment often has implications on other plant equipment and the desired benefits may not be realized because of other plant limitations.

Volume 1, Appendix B of these guidelines provides a general discussion on how to identify modernization opportunities. Modernization opportunities are classified into the following main categories:

- Energy
- Portfolio services, including capacity, storage, and river system regulation
- Ancillary transmission services
- Operational flexibility
- Automation
- Other services

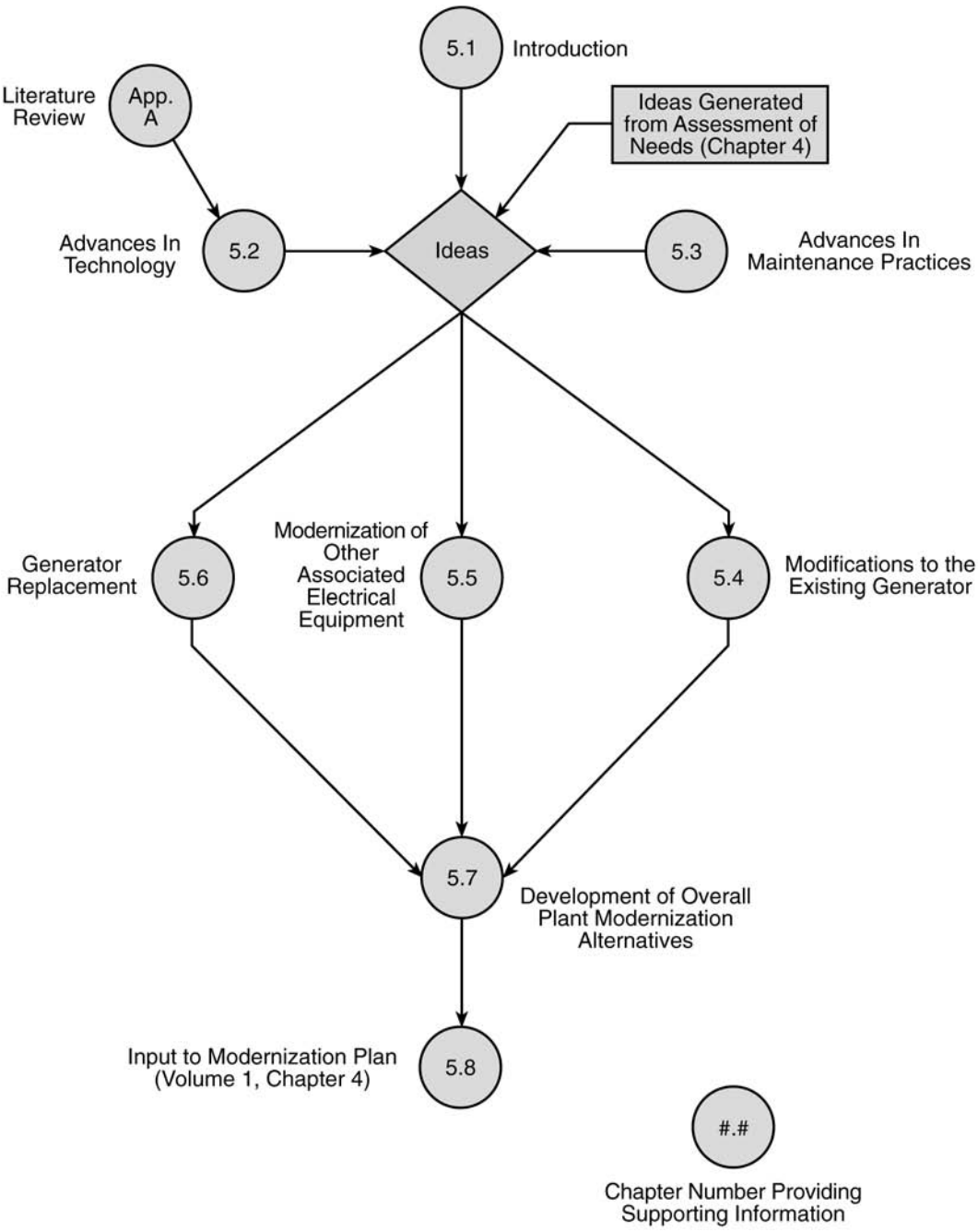

Figure 5-1
Potential for Improvements Process

The *pro forma* "Equipment Modernization Opportunities" worksheet (see Table 5-1), sometimes referred to as the *site worksheet*, can be used for recording modernization opportunities during the condition assessment process outlined in Chapter 4 of this volume. All opportunities identified should be included on the worksheets and then included in Table 4-3, "Data Analysis for Hydro Plants" and Table 4-4, "Data Analysis and Inspection Results for Equipment and Structures" of Volume 1, Chapter 4. Alternatively, the data can be entered directly into these tables. Table 5-2 is a summary of the areas of opportunity and activities to achieve these opportunities.

To assist in following the process, a depiction of Table 5-1 is provided at the start of each subsection of Chapter 5. The highlighted portion indicates the area covered by the text included in the subsection.

At the initial stage of assessment (that is, in Volume 3, Chapter 4), opportunities are identified but not quantitatively evaluated. This quantitative evaluation will be done when all opportunities from across the plant have been collected in Table 4-6 of Volume 1. Table 5-1 is used at this stage to ensure that all possible activities are at least identified for consideration. The worksheets should prompt thoughts on the magnitude of the modernization opportunity as well as its impact on plant products (such as the ability to provide peaking power and load-following capability) and the inter-relationship between modernization activities proposed for various equipment.

Table 5-1
Site Worksheet for Equipment Modernization Opportunities

Plant: _____
Equipment Name: _____
Unit Number: _____
Asset Number: _____
Prepared by: _____ **Date**:_____

<table>
<tr><td>Modernization Opportunities
(Chapter 5.2, 5.3, 5.4, 5.5, and 5.6)</td><td>Benefits of Modernization
(Chapters 5.4, 5.5, and 5.6)</td></tr>
<tr><td></td><td rowspan="3">Equipment:

Overall Plant:</td></tr>
<tr><td>Further Studies Required
(Chapter 7)</td></tr>
<tr><td></td></tr>
<tr><td>Impacts of Modernization on Other Equipment
(Chapter 5.7)</td><td>Other Equipment that Limits Modernization
(Chapters 5.5 and 5.7)</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Timing and Costs of Modernization
(Chapters 4.8 and 6.0)</td><td>Risk Evaluation of Modernization
(Chapter 4.6)</td></tr>
<tr><td></td><td></td></tr>
<tr><td colspan="2">Modernization Opportunities Selected for Input into Table 4-6, Volume 1</td></tr>
<tr><td colspan="2"></td></tr>
</table>

Table 5-2
Areas of Opportunity for Generator and Associated Equipment

Areas of Opportunity	Activities to Achieve Opportunities
Output • Increase unit capacity (subject to turbine, excitation, and auxiliaries) • Increase unit energy (availability and efficiency)	• Stator and field winding replacement • Stator core replacement • Field pole uprating • Unit uprating without equipment modification • Upgrade cables, circuit breaker, and transformer • Automation and P&C upgrades
Dependability • Age/equipment condition - identified equipment needs suggest areas of opportunity • Address operational improvements required • Address chronic equipment/plant problems • Improve plant/equipment reliability	• Remediation of condition defects • Replace rotating exciter with static excitation system • Replace/upgrade AVR • Replace/upgrade bearings using new materials such as PTFE
Sustainability • Reduce environmental risks; improve environmental compliance	• Install oil vapor removal and dust collection system • Improve inspection access • Re-wind stator to eliminate ozone emissions • Monitor ozone • Redesign generator cooling system to optimize water flow requirements or improve cooling air distribution • Replace exciter with a static excitation • Modernize generator fire protection system
Flexibility • Improve flexible operation for the plant as a whole (for example, load factoring, swing, and automated generation control)	• Perform MCM • Upgrade control systems • Provide for remote operation

5.1.1 Example of Completed "Equipment Modernization Opportunities" Worksheet

Table 5-3 is an example of a completed "Equipment Modernization Opportunities" worksheet for an excitation system. It was developed using the following sources:

- Volume 1, Chapter 4 and Appendix B for identification of opportunities
- The condition assessment process of Volume 3, Chapter 4 for the condition assessment
- Volume 3, Chapter 5 for further identification and assessment of the opportunities from a technical basis

Volume 1, Chapter 4 clearly delineates the process for identifying needs and opportunities of equipment and defining them sufficiently for the LEM plan. The flow of information between the process volume (Volume 1) and the technical volumes (Volumes 2–7), to support the development of the LEM plan can be complex. Figure 5-2 shows the flow of information in the process of identifying and defining modernization opportunities for the plant's electromechanical equipment.

Table 5-3
Sample Equipment Modernization Opportunities

Plant: Plant #1
Equipment Name: G2 Generator stator
Unit No.: 2
Asset No.: 1.2.4.1
Prepared by: I.M. Engineer Date: January 31, 2000

Modernization Opportunities (Chapter 5.2, 5.3, 5.4, 5.5, and 5.6)	**Benefits of Modernization** (Chapters 5.2, 5.5, and 5.6)
• Rewind with modern insulation system • Re-core using grain oriented steel for reduced magnetic losses • For coil windings, consider replacing with Roebel bar-type winding • Re-wedge and side pack with modern systems and materials • Install continuous on-line monitoring for factors such as partial discharge, ozone, and temperature • Add split phase monitoring • Use nonmagnetic materials for pressure fingers to reduce stray losses	• Increase generator efficiency • Increase generator capacity • Decrease unavailable time • Reduce maintenance costs • Improve generator protection
Further Studies Equipment (Chapter 7)	
Impacts of Modernization on Other Equipment (Chapter 5.7)	Other Equipment that Limits Modernization (Chapters 5.5 and 5.7)
Check capacities of the auxiliaries and current-carrying components, such as: • Generator bus • Unit breaker and transformer • Excitation system • Transmission lines • Turbine	Turbine; determine whether there is potential to upgrade or replace the runner
Timing and Costs of Modernization (Chapters 4.8 and 6.0)	Risk Evaluation of Modernization (Chapter 4.6)
1. A major overhaul required now due to decreased reliability from numerous bar/coil failures 2. Wedging or side-packing systems require replacement in five to seven years; replace with modern insulation system ($250K)	Increased generator capacity will cause additional stress to existing components, possibly resulting in reduced service life
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	
Rewind with modern insulation system in seven years; approximate cost of $250K	

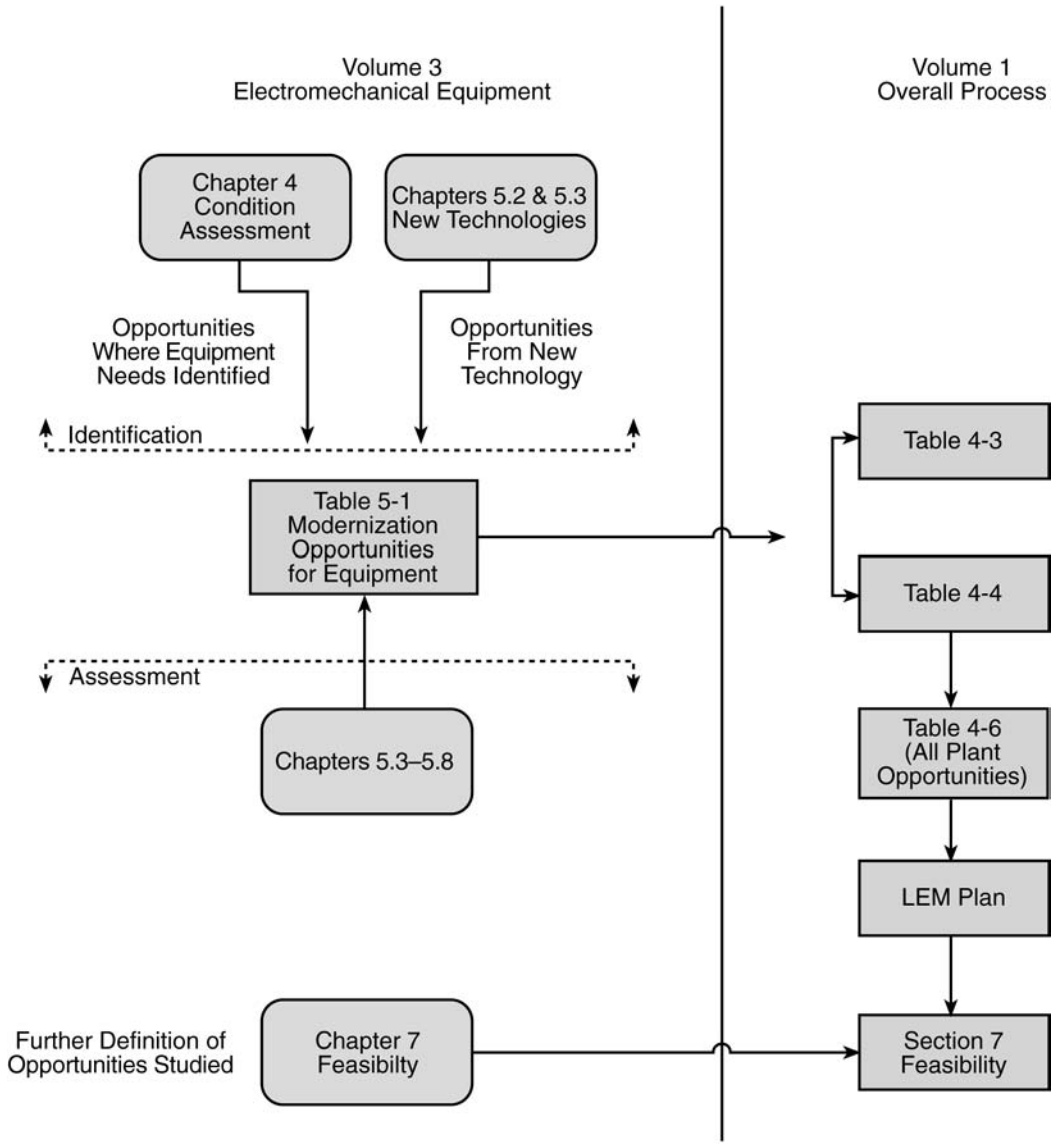

Figure 5-2
Flow of Information for Identifying and Assessing Modernization Opportunities for Electromechanical Equipment

5.2 State of the Art

Table 5-1

Modernization Opportunities (Steps 4 and 5, Volume 1)	**Benefits of Modernization (Steps 4 and 5, Volume 1)**
Further studies required	
Impacts of modernization on other equipment	Other equipment that limits modernization
Timing of modernization	Risk evaluation of modernization
Modernization opportunities selected for input into Table 4-6, Volume 1	

5.2.1 Introduction

Table 5-4, "Summary of Advances in Technology for Electromechanical Equipment," provides a quick reference for the modernization opportunities described in this chapter. Improvements in generator technology have been urged by the following drivers:

- The general requirement for increased power output/capacity at higher unit efficiencies
- Reducing outage frequency and duration
- Lowering maintenance/overhead costs
- Simplifying the process (that is, eliminating unnecessary plant items)
- Improving worker safety

Appendix A contains a bibliography that provides references for further reading on equipment modernization topics.

The opportunities presented by using newer technology are improved capacity, reliability, and profitability. They can be achieved through:

- Increasing output and efficiency of equipment
- Reducing operating and maintenance costs
- Increasing reliability

Table 5-4
Summary of Advances in Technology for Electromechanical Equipment

Equipment	Advances in Technology
Stator winding	• Electrical insulation operating at higher groundwall and thermal stresses • Improvements in thermal conductivity of insulation system • Improvements in gradient materials and application • Improvement in slot packing and wedging materials • On-line continuous PD monitoring • On-line continuous thermal monitoring • Higher voltage windings (for example, ABB "Powerformer") • Ozone monitoring • Split phase monitoring
Stator core	• Reduced magnetic losses using grain-oriented silicon steels • Consolidating lamination insulation • Laser cutting of core sheets • Pressure-following techniques for bolting • Nonmagnetic materials for pressure plates/fingers • Site stacking
Stator frame	• Welding/stress relieving for site fabrication/assembly • Finite element analysis • Expansion/contraction provisions
Field windings	• Thinner interturn insulation (Class H) • Molded insulation for collars/poles • Ability to power monitoring equipment off field • Ability to transmit operating data off rotor
Bearings	• Multi-viscosity mineral oil • PTFE thrust pads • Plastic bearing materials • Embedded thermocouples • Oil vapor removal systems
Excitation	• Static excitation using advanced power electronics to achieve higher field forcing • Digital control • Automatic brush lifters • Constant pressure brush holders

Table 5-4 (cont.)
Summary of Advances in Technology for Electromechanical Equipment

Equipment	Advances in Technology
	• Supervisory control and data acquisition instrumentation
Terminal equipment	• Compact CBs • Isophase buses • Plastic insulated cables
Fire protection	• Water suppression • Detectors and logic control
Braking system	• Non-asbestos brake pads (for example, fiberglass)
	• Custom-designed brake dust collection systems
Generator cooling	• Modulated flow of cooling water using control valves
P&C condition monitoring	• Digital, programmable, and self checking • Digital storage and high-speed analysis of signals • Ozone detectors, PD couplers, and IR detectors enable on-line monitoring • Modeling and prediction • Vibration monitoring/diagnostics

In general, the use and development of computer-based technology has been a catalyst for enabling many of the developments outlined below.

Although the information that follows is current at the time of report development, it will eventually become dated. The user is encouraged to check for developments in technical journals and conference proceedings and with manufacturers and suppliers.

5.2.2 Generator

The improvements to generators have been achieved by the following:

- Using better insulation materials that require less space and allow more copper to be installed per unit volume with subsequent higher power output per unit volume
- Implementing better testing and monitoring techniques that allow improved operating techniques
- Using innovative construction/overhaul methods
- Eliminating the requirement for items such as the generator low-voltage breaker, transformer, and associated switching equipment
- When possible, switching from multi-turn lap windings to single-turn wave windings, which will reduce dangerous turn-to-turn failures and ease relaying

5.2.2.1 Design

Original Equipment

Several design changes may be considered. For stator windings, single-turn Roebel bars may be superior in ratings to even a modern multi-turn coil rewind. Increasing the air gap reduces thermal heating of field pole pieces but may result in a loss of reactive power. Conversely, new field poles and windings (with possible air gap reduction) and using Ammortisseur pole face windings may increase power output. Changes to the air circulation may be necessary to decrease temperatures concurrent with increased outputs. The owner should consult with an OEM about design change to ensure that all electrical, mechanical, and thermal design parameters are professionally considered.

Powerformer

The technology to eliminate the generator transformer and its associated equipment has recently been developed. The recent construction in Sweden of a generator with high voltage output, known as Powerformer, has eliminated the need for a generator transformer and its associated equipment. The concept has been developed by Asea Brown Boveri (ABB) and it appears to have efficiency benefits along with risk reduction benefits due to the absence of the generator transformer and its associated equipment. Depending on design, the Powerformer has the potential to generate at voltages up to 130 kV. The improvement is achieved with the use of round high-voltage cables as conductors in the stator in lieu of the traditional square conductors. The Powerformer has the benefits of no PDs and, because of its robust design, it can be overloaded for long periods. In addition, because the Powerformer operates at significantly lower temperatures than conventional generator designs, it is less susceptible to the stresses from thermal cycling. It is thus more suitable in applications where frequent stops and starts are required.

5.2.2.2 Materials

Generator output can be improved by the use of thermo-setting materials as insulating media. The new materials allow more copper to be inserted into the generator during the rewind process. This is possible because the same level of insulation performance can be achieved with smaller quantities of thermo-setting plastic insulation that allows more copper to be accommodated in the original generator volume. An automatic uprating of between 15% and 25% can be expected from a rewind using modern insulation.

Better heat transfer characteristics are also a benefit of using modern insulating materials. Thermo-setting insulation and polymer bar coatings are also being used in place of conventional side packings for windings to improve thermal and mechanical performance. The use of low-loss cores using grain-oriented silicon steels is also a feature of modern generators. In the future, superconductors may further improve the capabilities of generators; however, more research is required in this area.

5.2.2.3 Operation

Modern practice is to operate generators closer to the full temperature limit of their modern insulation system (typically Class F instead of Class B), allowing increased generator output. However, such a practice must be tempered by heat run tests and consideration of all thermal and mechanical impacts.

With the advent of on-line condition monitoring, the ability to monitor and trend operational parameters has improved significantly, allowing the generator to be operated at near its actual capability limits rather than its nameplate rating.

5.2.2.4 Ozone Monitoring

Overview

Ozone monitoring is a complex topic. If generator ozone levels are high enough to be an equipment problem, they will also likely present a safety hazard to employees.

Although there are many ways to measure ozone levels, only the ultraviolet (UV) absorption ozone analyzers (the type used for continuous environmental monitoring) can provide the accuracy and precision required to monitor ozone levels inside and outside generator enclosures. Multi-source air sampling systems are used to sequentially switch air from various sample points to a single gas analyzer for analysis.

Most portable instruments and gas sampling tubes (for example, Draeger tubes) do not provide sufficient accuracy. Reasonably accurate spot checks (plus or minus approximately 10%) can be achieved using nitrite-impregnated glass fiber filters and laboratory analysis using ion chromatography. The problem with spot checks is that they provide only a snapshot in time of ozone levels. Ozone levels can vary significantly over time due to a number of factors.

Accuracy of Ozone Measurements

The accuracy of the ozone measurements depends on regular maintenance and calibration procedures. If the air filters required on each air sample line are not replaced regularly, the contaminants will accumulate and the airflow will be restricted, resulting in false low measured values. Field calibration of UV ozone analyzers is done with special ozone generator transfer standards whose accuracy is traceable to national standards.

Ozone measurement accuracy can vary from ±5% to ±50% of the indicated value, depending on the technology being used and a number of other factors. Devices used for ozone measurements can often be configured for a number of different gases, so it is important to determine the measurement accuracy for the instrument with its ozone-specific sensor, as well as the ozone sensor's cross sensitivities to other chemical compounds. With many devices, the presence of other oxidizing gases such as chlorine compounds, acid fumes, and NO_x can increase the indicated value. Strong reducing gases, such as vapors of alcohol and solvents, can reduce the indicated value. Any substance that results in contamination of intake tubes or filters also degrades accuracy.

Sampling Methods and Issues

A number of factors must be considered when selecting ozone measuring equipment, including the characteristics of ozone, the sampling times of different methods, and whether occasional spot checks (grab samples) are sufficient or continuous monitoring is required. There are also site-specific issues such as the number of sampling points and the variability of ozone levels with time, operating conditions, and other factors.

5.2.3 Excitation Systems

Exciter technology has embraced the use of static exciters (which first appeared in the 1960s) over rotary exciters. The first static exciters used mercury arc rectifiers to convert ac to dc; modern design uses solid-state power electronics.

Voltage regulation improvements have centered on digital control improvements in line with excitation power component improvements. The modern AVR is digitized and a key component of the modern excitation system. The digital AVR can be quicker and easier to troubleshoot and maintain because digital AVRs, unlike their analogue predecessors, do not require additional hardware for each additional function they perform. Because the additional functions are incorporated into the software of the digital AVR, there is less hardware to break down.

A digital excitation control system can provide more features than its analogue counterpart. In addition, the digital systems are drift free, an improvement on the analogue excitation system in which gains and time constants tend to drift over time.

5.2.4 Bearings

5.2.4.1 Teflon™ Thrust Bearing

Advances in the use of Teflon™-like material for thrust bearing surfaces have been successfully applied in a variety of hydroelectric power plants outside North America, most notably in large turbine units in Eastern Europe. This technology was first introduced in the USSR 20 years ago to address bearing failures during startup before hydrodynamic oil films had been generated and where the bearings rely on the high-pressure oil injection systems. Reportedly, these Teflon materials, which have been in use since the late 1970s, are effective in applications with thrust loads of up to 3500 tonnes and bearing pressures of up to 1000 psi (6.89 MPa) on units installed, specific loads approximately three times the normally accepted limit for white-metal (babbitt). These advanced bearing materials have advantages over traditional babbitt-bearing materials and may be the solution to ongoing bearing problems experienced at some North American plants.

The characteristic of the Teflon bearing to operate safely with minimal oil film thickness permitted the development of very large bearings, operating at pressures in excess of 10 MPa and without high-pressure oil injection.

A typical PTFE thrust pad consists of a PTFE surface layer mechanically bonded onto a wire mesh that in turn is soldered on to the steel base.

Although the capability of PTFE-faced thrust pads to operate safely without the need for high-pressure oil injection systems is generally seen as a benefit, there may be some circumstances in which it would be desirable to have a lift pump available. Examples include (a) when a pumped storage machine is required to start in either the spin/generate or spin/pump modes, (b) when low starting torques are an advantage, or (c) during machine installation or maintenance when it might be necessary to rotate the shaft at low speed using low-torque bearing devices. Because of the materials and the method of construction of PTFE-faced pads, the provision of high-pressure oil injection is not as straightforward as it is for white-metal-faced pads.

Some companies offer slight variations on pure Teflon bearings, incorporating carbon and/or graphite in a filled grade with superior wear resistance.

The advertised advantages (courtesy of Michell Bearings) of PTFE over white-metal (babbitt) include the following:

- Increased load-carrying capacity up to 1460 psi (10 MPa), which is typically three times that of white-metal
- Superior friction and wear characteristics during start and stop
- Elimination of high-pressure oil injection
- Reduced power losses (typically 20–30%) due to reduced bearing size
- Forgiving material: PTFE is chemically inert and does not exhibit the type of catastrophic failure often associated with white-metal
- Reduction in overall costs due to:
  - Smaller shaft forgings
  - Smaller bearing housing
  - Smaller lubrication systems
  - No high-pressure oil injection
  - Smaller coolers
  - Improved efficiency of generator
  - Reduced power losses
- Lower braking speeds (which leads to less dust pollution)
- High ability to absorb shock that can reduce vibration from rotating parts
- Sixfold increase in resistance to wear using filled grade as compared to pure PTFE
- Spare parts usually consist of one pad instead of an entire bearing

5.2.4.2 Nonmetallic Guide Bearings

There is some movement toward the application of nonmetallic guide bearings. The application has been limited to replacing lignumvitae with various types of plastics in water-cooled turbine

bearings. To date there is no report of using nonmetallic bearings in generators. One utility has experimented with installing a plastic style bearing to replace a water-cooled babbitt bearing with some success.

5.2.4.3 Vapor Removal Systems

Labyrinth and felt vapor seals are not always effective in preventing oil mists, resulting in surface contamination of structures, the core, and windings. Such contamination attracts dust and dirt accumulation and may reduce cooling. Simple vacuum systems with vapor condenser/collection provisions can be effective. Other alternatives that should be investigated are improved seal design or the use of positive air pressure around the bearings.

5.3 Equipment Maintenance: Changes in Approach/Improvements

Table 5-1

Modernization Opportunities (Steps 4 and 5, Volume 1)	**Benefits of Modernization (Steps 4 and 5, Volume 1)**
Further studies required	
Impacts of modernization on other equipment	Other equipment that limits modernization
Timing of modernization	Risk evaluation of modernization
Modernization opportunities selected for input into Table 4-6, Volume 1	

These guidelines are not intended to describe maintenance practices and techniques. At times during the use of these guidelines, however, it is only natural that maintenance will be discussed when assessing a generator's performance and outlook for the future. Accordingly, this chapter will only comment on some of the advances in high-level equipment maintenance approaches.

5.3.1 Predictive Maintenance

The following are the drivers for the use of predictive maintenance and condition monitoring:

- Increased reliability
- Increased intervals between planned outages
- Decreased forced outages and durations

Predictive maintenance involves the collection and interpretation of operational data to predict maintenance requirements (and correct defects before a major problem or failure develops) and optimum scheduling.

The aim of using predictive maintenance is to extend maintenance intervals beyond the existing, time-based preventive maintenance periods. Predictive maintenance also seeks to identify and rectify problems before they become catastrophic, which may not have been possible by relying on time-based preventive maintenance techniques. Ultimately, predictive maintenance is a maintenance approach designed to:

- Reduce the risk of equipment failure
- Reduce overall maintenance costs
- Improve commercial availability
- Minimize secondary damage

5.3.2 Machine Condition Monitoring

MCM is used to provide a more comprehensive predictive maintenance program. It collects performance data, either continuously or periodically, such as vibration, temperature, flow rates,

PD, and displacement. These data, at present, are interpreted off-line to predict maintenance requirements. Many attempts are underway to use MCM systems on-line that will continuously monitor parameters and provide "smart" alarms that are more predictive. Present status alarms, which alert the operator that a set point has been reached, typically do not allow for outside parameters. Monitoring during successive start, stop, overload, overspeed, and fault operations and comparative analysis provide valuable trend information to the operator.

An example of the use of a "smart" system of MCM would be an alarm that alerts the operator to a problem with a turbine guide bearing temperature at half load, which (in terms of maximum allowable bearing temperature) is not critical but is an indicator of a problem occurring. By identifying the problem earlier, there is the opportunity to investigate and perhaps fix the problem at a more convenient opportunity as opposed to later, when the problem is identified at full load and a forced outage is not desirable.

The following are four key benefits of applying MCM technology in generating stations:

- Value of increased system capacity - The potential of hydroelectric MCM to enable planned "overloading" of generating units that are monitored to ensure minimal impact on equipment life and maintenance costs could add to overall system peak capacity, thus avoiding the incremental cost of acquiring new generating capacity. Less reserve capacity would also be necessary for covering periods of planned and unscheduled outages if these outages are reduced.
- Energy value from using present "spills" - Water is sometimes spilled when there is excess water behind a dam or when generating units are out of service for maintenance or repairs. The potential for hydroelectric MCM to enable planned overloading and reduce maintenance and repair downtime could permit more water to be run through generating units, thus providing an increased energy output.
- Value of reduced timely maintenance and repair outages - Presently, generating units are usually taken out of service on a time-scheduled (calendar-driven) maintenance program or when a failure has occurred (machine trip or human detection). An effective hydroelectric MCM system, which enables "condition-driven" maintenance, has the potential to reduce maintenance costs by helping to ensure that maintenance work performed is necessary when undertaken and that ample warning is given to minimize system utilization problems.
- Value of life extension for aging equipment - The implementation of an effective MCM system would enable the informed deferral of equipment rebuilds as compared to the present system of calendar-driven (scheduled) equipment rebuilds.

In addition to these key benefits, other financially tangible and intangible benefits may include the following:

- Improved generating unit operating efficiency
- Improved system efficiency
- Improved risk management on "run-of-the-river" plants
- Improved outage planning (system balancing and substitution)
- Improved environmental monitoring

- Improved safety
- Reduced spare part inventories
- Improved operational and maintenance skills

A problem with implementing condition monitoring in a hydro plant is that the plant typically has very slow wear rates. Changes in performance, which provide the trends that condition monitoring relies on, occur gradually; trending of these parameters must take this into account.

5.3.3 Reliability Centered Maintenance

History of RCM

Reliability-centered maintenance (RCM) was first developed by the commercial aviation industry in the late 1960s. To establish the economic viability of the larger, more complex wide-body jets, with increasing concerns over public safety, a different approach to maintenance was required. The approach taken was to preserve system function rather than equipment operation, the objective of traditional maintenance. RCM was accepted by the U.S. Federal Aviation Administration and became an industry standard.

In the mid-1970s, the U.S. Department of Defense, under pressure to reduce O&M costs of its military aircraft without sacrificing reliability, adopted the same philosophy.

In the early 1980s, RCM pilot applications in the nuclear power industry revealed a reduction in the number of forced outages and an estimated 30–40% savings in maintenance costs. By the mid-1990s, EPRI—working with transmission and distribution utilities—was conducting pilots on applications in substations, and RCM software was replacing manual spreadsheets for analysis and record keeping.

What Is It?

RCM is a structured method for developing an initial maintenance program or for optimizing an existing maintenance program to preserve critical system functions based on safety, operational, and economic criteria.

RCM is a structured decision-making process that assembles the various proven maintenance standards, including time-based preventive, condition-based or predictive, and operate to failure, using a benefit optimization approach to establish a new maintenance strategy. The philosophy is to maintain critical systems; noncritical or redundant systems may be allowed to fail.

RCM comprises the following basic steps:

1. Select the functional system, for example, stator winding and exciter
2. Define system boundaries, for example, insulation resistance and pole drop
3. Identify critical system and component functions
4. Perform a failure mode and effects analysis (FMEA)
5. Select appropriate maintenance tasks at an optimized frequency
6. Compare the maintenance tasks selected to current ones
7. Group tasks and implement new maintenance program
8. Implement a process in which the program is reviewed as conditions change

The heart of RCM is FMEA, which is used to study critical systems and determine how they can be best maintained to avoid component failures and improve overall reliability. This is accomplished by asking seven questions:

1. What is the function of the device?
2. How can it fail?
3. What is the cause of each failure?
4. What happens when a failure occurs?
5. Why does the failure matter?
6. What can be done to prevent or predict each failure?
7. What can be done if a suitable proactive task is not available?

The process is powerful for the following reasons:

- It is a structured, logical approach that creates a documented maintenance program.
- It identifies critical equipment that may not have been maintained to date.
- It incorporates all of the different maintenance styles in an optimized format.
- It readily accepts the input of knowledgeable trade and technical people.
- It can be easily modified as equipment and process changes occur.

It is not intended to address design concerns, although the process may identify as yet unidentified, design-related equipment issues. It also does not address inadequacies in training, work procedures (quality issues), or the occurrence of human error.

What Are the Benefits?

The results of a fully implemented RCM program typically yield the following:

- Increased confidence to meet operations requirements
- Increased unit availability
- More efficient expenditures of maintenance dollars

In summary, the benefits of RCM are significant when fully implemented. The risks are that its implementation is under-resourced or that senior management does not give it the priority or focus it needs.

5.4 Modernization of a Generator

Table 5-1

Modernization Opportunities (Step 4-5, Volume 1)	**Benefits of Modernization (Step 4-5, Volume 1)**
Further Studies Required	
Impacts of Modernization on Other Equipment	**Other Equipment that Limits Modernization (Step 4-5, Volume 1)**
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

Chapter 5.4 discusses the equipment modernization options that involve modifications to the existing generator rather than replacement of it. Any equipment modifications considered should be input into their Equipment Modernization Opportunities worksheet (Table 5-1) for future consideration as part of the LEM plan.

Table 5-5 summarizes the possible equipment modifications.

Table 5-5
Upgrading Activities: Generator Modifications

Chapter	Modification
5.4.2	Uprating without equipment modification
5.4.3	Stator re-winding
5.4.4	Stator core replacement
5.4.5	Field winding and pole uprating

5.4.1 Introduction

The modernization alternatives for the generator range from rehabilitation or replacement of one or more of the major components to a complete generator replacement.

Hydroelectric generators in older power plants were conservatively designed and constructed and, generally, have potential for improved performance. The greatest potential exists in the ability to increase generator capacity by modifying the generator design and by upgrading major components. This is accomplished with more efficient winding designs and improved insulation materials capable of operating at higher temperatures. Improvement in generator efficiency is also possible but less significant because the relatively high efficiency of older units is between 94 and 98% as shown in Figure 5-3. Although modern generator designs can significantly reduce generator losses, the increase in efficiency is only approximately 1–1.5%.

Of this improvement, approximately two-thirds can be achieved through reduced copper losses (due to rewinding) and approximately one-third through reduced iron losses (due to restacking). Typical iron core material losses for the year of equipment delivery are shown in Figure 5-4. It may also be possible to reduce ventilation or windage losses by redirecting or limiting the airflow if the existing machine is overventilated. The amount of reduction depends on the design of the particular generator. However, if modernization results in higher capacity, care must be taken in ventilation re-design.

The evaluation and feasibility of generator modernization alternatives will be based on the condition of the existing generator and the owner's criteria for evaluating generation benefits and capital expenditures. Because these criteria will vary, clear-cut modernization recommendations cannot be provided. However, the following generalizations can be used:

- Prior to 1960, generators were conservatively designed with low capability factors compared to more modern designs and, consequently, pre-1960 generators have much greater uprating potential. Generator capability factors and methods for determining the generator uprating potential are discussed later in this chapter.
- The principal generator components that can be modified to uprate the generator are the stator winding, stator core, field poles, field windings, cooling system, and excitation system. Modification to the stator frame and bearing supports may be necessary if capacity is increased.
- If the existing stator winding and insulation are in good condition, a moderate increase in temperature rise may be permitted within the existing temperature limits, which would allow uprating with the same winding. It should be noted, however, that the increased temperature will accelerate thermal deterioration of the winding (a rule of thumb: the remaining life of the insulation system is cut in half for each 10°C increase in operating temperature).

- If the winding is more than 20 years old, uprating will generally be possible with a new winding using modern insulation systems. The newer insulations are generally thinner, allowing more copper cross section in the slot, which permits the uprating. A capacity increase of 15% can be expected. This uprating must be coordinated with the capability of the field winding and excitation system. Before rewinding, consideration should also be given to winding design changes, including Roebel bars instead of coils, wave windings, and so on.
- Fitting a new stator winding into an old core may not be economical, because the core reliability will not be improved and high localized core losses may reduce winding life. Therefore, testing and assessment of the stator core condition are essential, and repair or replacement may be required for any rewinding. Repair of old cores is often not feasible because the deteriorated interlaminar insulation would be damaged further during the unstacking/restacking process. Furthermore, experience indicates that a firm, precision fit of the winding in the stator slots is of utmost importance for a successful rewinding. Stator slots of old cores that had soft asphalt-mica insulated coils installed were not designed or built to precise slot dimensions. Therefore, installing new hard-coil windings in old inexact cores involves the risk of reduced winding life and performance. In addition, the reduced iron losses of a new core (as shown in Figure 5-4) may justify core replacement.
- It is not cost-effective to repair, replace, and/or uprate the stator core and stator winding if the required magnetic flux increase cannot be provided by the existing exciter.
- Unacceptable vibrations may also result from defective field coil interturn conditions. In such a case, all field coils should be repaired or replaced.
- A major cost of component repair or replacement is disassembly and lost generation. Therefore, after the decision to disassemble the generator is made, modernization of all aging components may be cost-effective.

The analysis of generator condition and upgrading potential is complicated because each major generator component has a different operating life and is designed with a different safety factor. As a result, generator upgrading is typically considered in steps of increasing output as additional and more extensive component modifications are made. Thus, the design or operating capability of the original generator may be changed, which further complicates the upgrading analysis.

Although endless upgrading combinations of new and old generator components may be possible, the following generator modernization alternative cases were selected to represent the range of generator and exciter equipment modifications that can exist. The cases appear in order of increasing output potential and equipment modification:

- Uprating without modification
- Exciter replacement
- Stator rewinding
- Uprating of field winding and poles
- Stator rewinding and core replacement
- Replacement of the whole generator

The first five cases will be discussed in more detail in subsequent paragraphs of this chapter. Generator replacement is discussed in Chapter 5.6. Modification or replacement of cooling system and turbine components may be required to accommodate the higher output but are not considered here.

5.4.2 Uprating Without Modification

The design criteria that determine the capability of electrical components, such as the generator, switchgear, transformer, and transmission line, are the apparent output or apparent capacity in kVA and not the active capacity measured in kW used to denote unit and plant capacity. Power factor (cos Φ) is used to convert between apparent and active capacity where kVA x cos Φ = kW. The power factor relationship determines the capability of the equipment to generate, transform, or transmit reactive power in addition to active power to meet the grid system requirements.

Older hydro plants were often developed in remote locations and connected to load centers by long transmission lines, which required relatively high reactive power capability. Consequently, the rated power factors for old hydro generators are often relatively low and are in the range of 0.85 to 0.75.

Today's electrical grid system is different, and the need to generate and transmit reactive power from the hydro plant may be much lower than when the plant was originally built. Therefore, the power factor requirement of the plant should be investigated in conjunction with modernization and updated if possible. Subsequent modernization plans should then be based on the updated power factor in calculating electrical equipment active power (in MW). Quite often, limiting the power factor range to 0.90 to 0.95 can allow a 10–20% increase in active power capacity of the electrical equipment without modification.

The results of the OEM temperature rise tests, or other tests described in the previous section, can provide an indication of the uprating or overload potential of the generator. By plotting the results of the stator and field winding temperature rise versus generator load, the output limit corresponding to the temperature rise limit can be estimated by projecting the temperature rise trend until the temperature rise intersects with the temperature rise limit, as shown in Figure 5-5. Referring to this figure, output limit A corresponds to the stator temperature rise rating of 60°C and an output of approximately 109.5% of the existing generator rating; output limit B corresponds to the field limitation of 111.8%. The generator output limit would be the lower figure, 109.5%, which is the maximum generator output achievable without exceeding the stator winding temperature.

Most hydroelectric generators with thermoplastic (asphalt or shellac bonded mica) insulation were designed to meet ANSI C50.12 (published in 1965) or a previous issue. This standard was revised in 1982 and reaffirmed in 1989. Major changes included an increase in the permissible temperature rise, a change in the definition of rated output, and deletion of the service factor of 115% rated output.

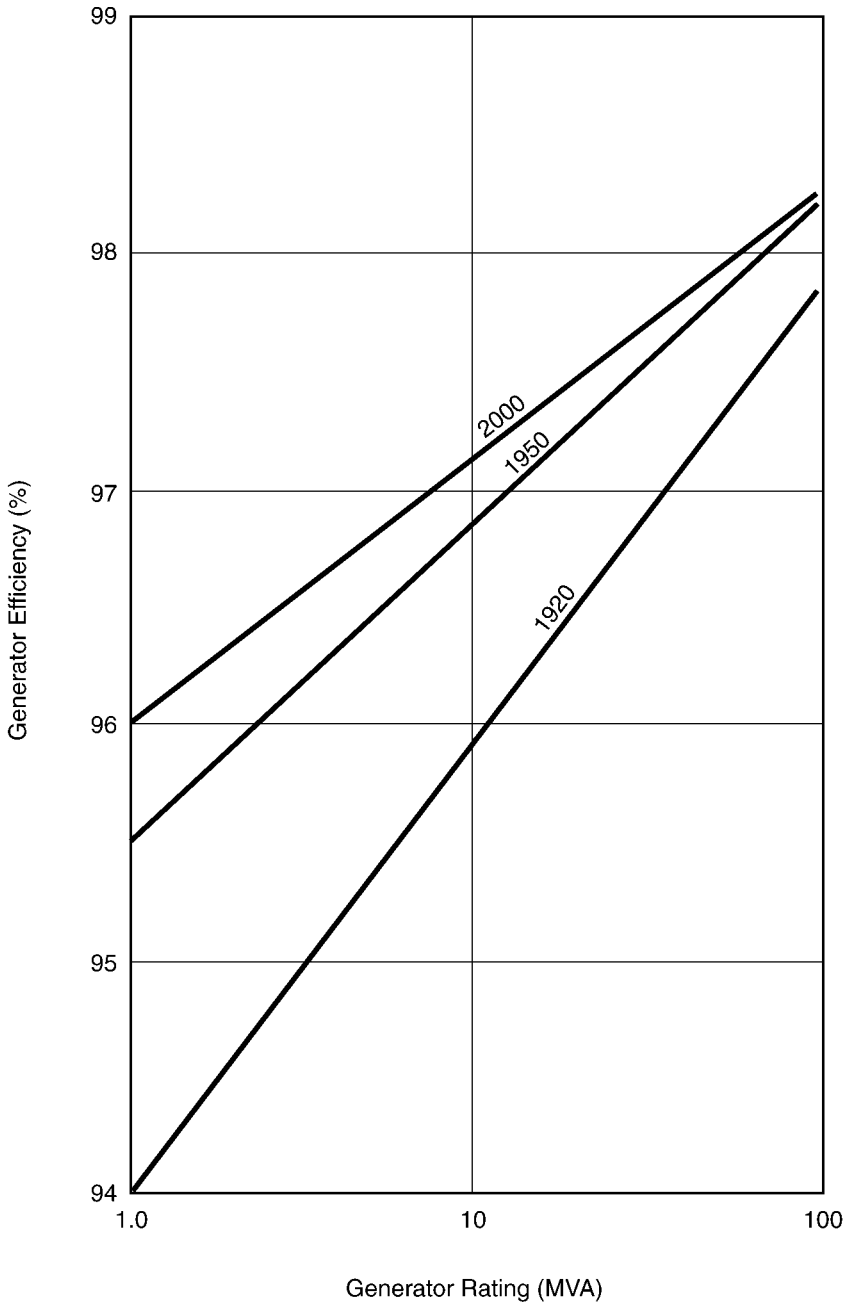

Figure 5-3
Generator Efficiency at Rated Load, Power Factor 0.9 for Various Years of Construction

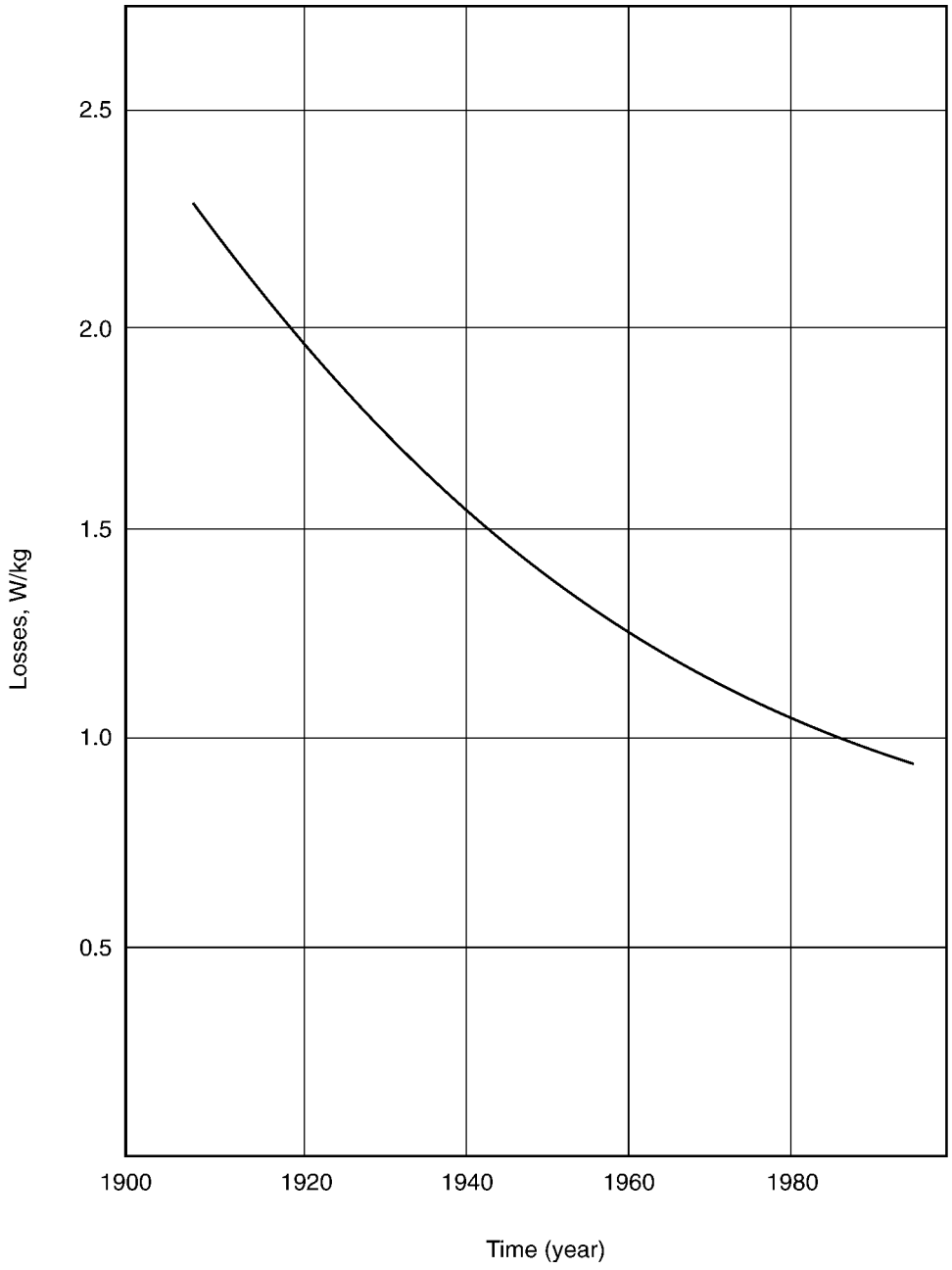

Figure 5-4
Typical Iron Core Material Losses in W/kg Over Year of Delivery

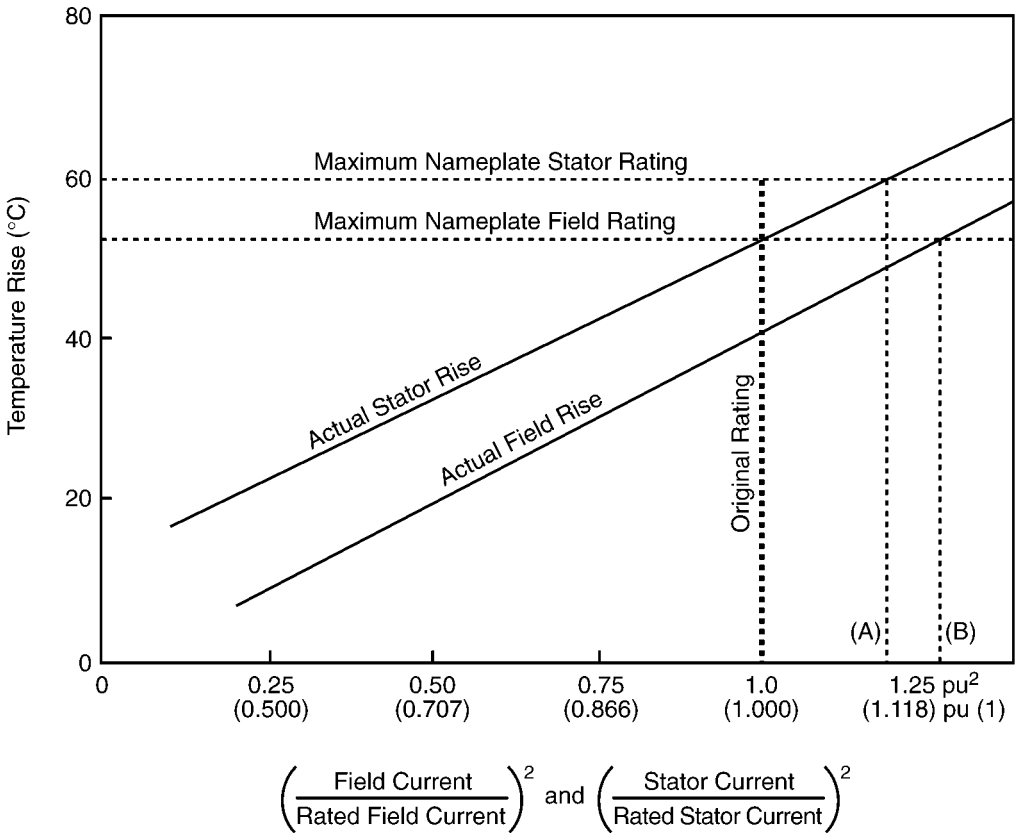

Figure 5-5
Uprating Using Benefit of Conservative Design

Prior to 1982, ANSI C50.12 provided for a double rating. For rated output, a moderate temperature rise figure (typically 60°C for Class B windings) was the guaranteed limit that would never be exceeded under continued operation at rated output. A continuous overload operation range up to 115% of the rated output was also permitted at a temperature rise above 60°C. The temperature rise limit was not specified; however, continued overload operation was noted to be harmful to the generator, and accelerated insulation aging would result by continued overload operation.

Overload operation reduces the insulation life of shellac and asphalt-bonded Class B or "soft coil insulation" whose aging mechanisms are swelling, formation of voids, asphalt migration, compound dripping, and disintegration of the insulation under increasing attack of internal corona. Insulation life is essentially time and temperature dependent.

Other increased temperature concerns include additional thermal stresses and expansion of stator bore, frame and housing, and possible effects on generator bearings and rotor structural components.

Higher operating temperatures and higher temperature rise limits are permissible for modern Class B or F epoxy/polyester resin-bonded or thermosetting "hard coil insulation." As a result, the ANSI C50.12, 1982 Standard specifies higher allowable values for temperature rise for continuous rated output. Typically, the allowable temperature rise limit is 80°C (75°C for

machines above 7000 V) for Class B windings. The continuous rated output is a maximum rated output of the generator that cannot be exceeded. The rated output can be increased in proportion to the increase in temperature rise limits above the previous 1965 output rating. However, care must be exercised regarding actual operating temperatures.

For generator uprating, it is helpful to use the rated output and temperature rise definition in accordance with the 1989 issue of ANSI C50.12. The maximum permissible output is simply called *rated output* and is defined as the maximum output that must not be surpassed. The new rated output can be estimated as the original nameplate rating times the square root of the ratio of temperature rises. Actual output rating will be determined by performing heat run testing and considering other components. The heat run should be carried out in accordance with accepted standards such as IEEE Standard 115.

It is recommended that a new nameplate be installed following modification and testing that states the rated output, insulation winding class, and the temperature rise in accordance with ANSI C50.12, 1989.

5.4.2.1 Stator Winding Temperature Rise

The generator may be capable of delivering more power if an increase in temperature rise is feasible. Methods for determining the existing stator and field winding temperature rise are described in Chapter 4. The maximum allowable temperature rise for each uprating case and class of insulation material will consider good engineering practice, manufacturer's operating instructions, limits prescribed in the standards, and the actual condition of the generator. On older units, the uprated temperature rise is often limited by the maximum design value of the original generator. Although slightly conservative, this is done in recognition of the fact that thermal stresses are difficult, if not impossible, to quantify. Discussions with manufacturers and designers tend to support this guideline. The following formula can be used to calculate the maximum rated output, S_2, for the stator winding where rated output is defined as maximum continuous rating per ANSI C50.12.

$$S_2 = (S_1)\, x \sqrt{\Delta t_2 / \Delta t_1}\, x \sqrt{A_{cu2} / A_{cu1}} \qquad \textbf{Eq. 5-1}$$

where:

S_2 = rated output of the uprated generator (kVA)

S_1 = rated output of the existing generator (kVA)

Δt_2 = temperature rise for output, S_2, corresponding to the maximum permissible uprating capacity, S_2, in kVA

Δt_1 = temperature rise measured for the existing rated output S_1 in kVA

A_{cu2} = copper cross-sectional area of new conductor

A_{cu1} = copper cross-sectional area of old conductor

The calculated uprated capacity should be taken as approximate and only for study purposes. Additional factors such as heat transfer, cooling characteristics, increased excitation currents, and increased magnetic flux levels must be considered as part of a detailed design analysis of anticipated temperature rises.

In addition, overall decreases in unit efficiency due to higher turbine losses may occur when output is increased. In such cases, target uprated capacities cannot be achieved.

5.4.3 Stator Rewinding

Stator windings are usually replaced during the life of a generator when winding failures occur or when the potential for failure exceeds acceptable limits. The need for stator winding replacement often provides the impetus for upgrading the turbine and other generator components. Stator rewinding may also be warranted if the maximum uprating potential of the existing generator is inadequate to fully use the turbine capability.

Stator rewinding should be considered if the existing stator windings are determined to be in poor condition during inspection or by the dielectric measurements discussed in Chapter 4, "Performance Evaluation and Condition Assessment."

Modern mica thermosetting insulation has a higher temperature rating than the older mica thermoplastic insulation materials. The higher temperature rise capability is recognized by ANSI Standard C50.12, 1989, which permits a 20°C (15°C above 7000 V) higher temperature rise for Class B thermosetting windings than for thermoplastic windings. As a result, a generator can operate at a greater output if a higher temperature rise is allowed. It is widely practiced and recommended that thermosetting insulations be limited to a temperature rise of 80°C as permitted for Class B, although these insulations are in fact Class F and, according to standards, would be allowed a 90°C temperature rise.

For example, Figure 5-6 shows that if the stator temperature rise is increased from 60 to 75°C, the stator current squared could be increased 27% and, consequently, the generator output approximately 13% ($\sqrt{1.27}$ =1.13). If the temperature rise under existing conditions and load is less than 60°C, the potential uprating could be greater.

Modern windings with thermosetting, state-of-the-art quality insulation can withstand a higher electrical stress per unit thickness than the older, thermoplastic, semi-soft insulation materials. To maintain the same overall voltage capability, the insulation thickness can be reduced, as shown in Figure 5-7, which allows more copper to be included in the new stator winding while maintaining the same external dimensions and slot size. The increased conductor cross section results in reduced losses, and the thinner winding insulation improves the heat dissipation, as shown in Figure 5-8.

Where multi-turn coil windings are installed, replacement with single-turn bars (half coils) of the Roebel type or single-turn coils should be considered. The Roebel bar winding has internally transposed subconductors and does not need the interturn insulation required for multi-turn windings. The copper can be increased for the same slot size while the insulation is reduced. As

a result, the losses and heat dissipation are improved. Coils with modern insulation can be mechanically overstrained at the coil knuckles during installation, potentially causing fractures. Overstraining can be avoided with Roebel half-coils or bars.

Multi-turn coil windings can be replaced by Roebel bars if two conditions are met:

- The number of turns per coil equals the number of parallel circuits in the stator winding
- The stator core length is greater than 20 times the turn depth to accommodate the transpositions

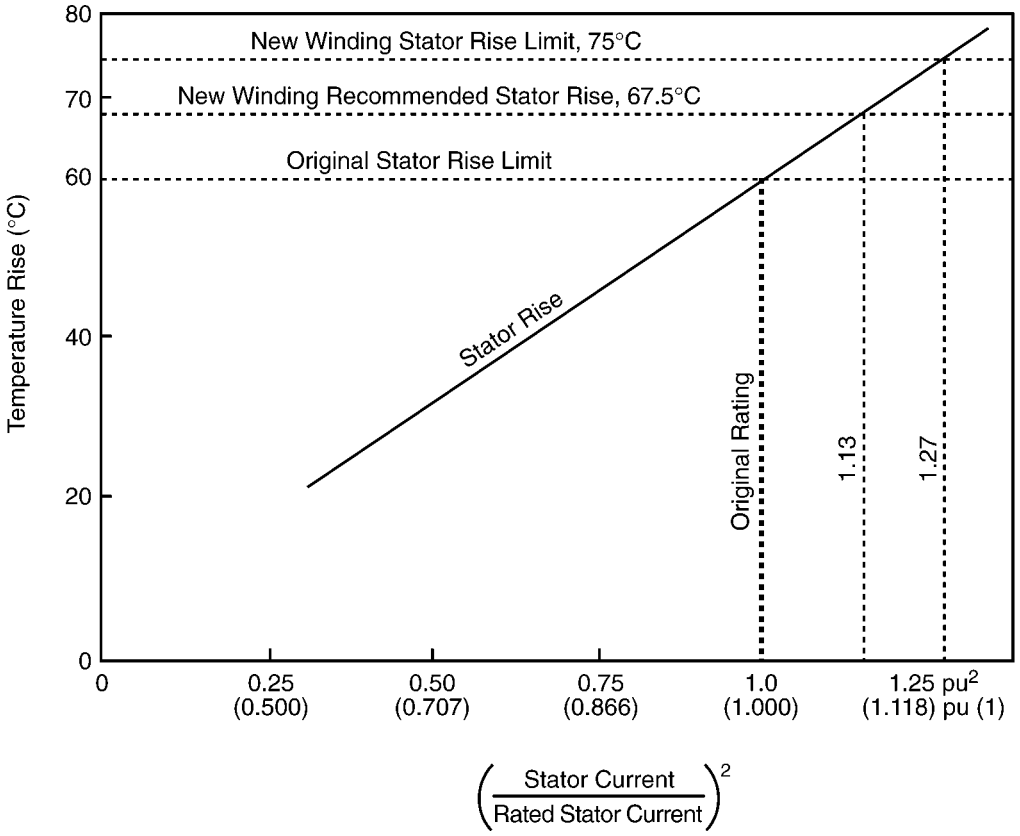

Figure 5-6
Example of Temperature Rise Versus Stator Current Squared

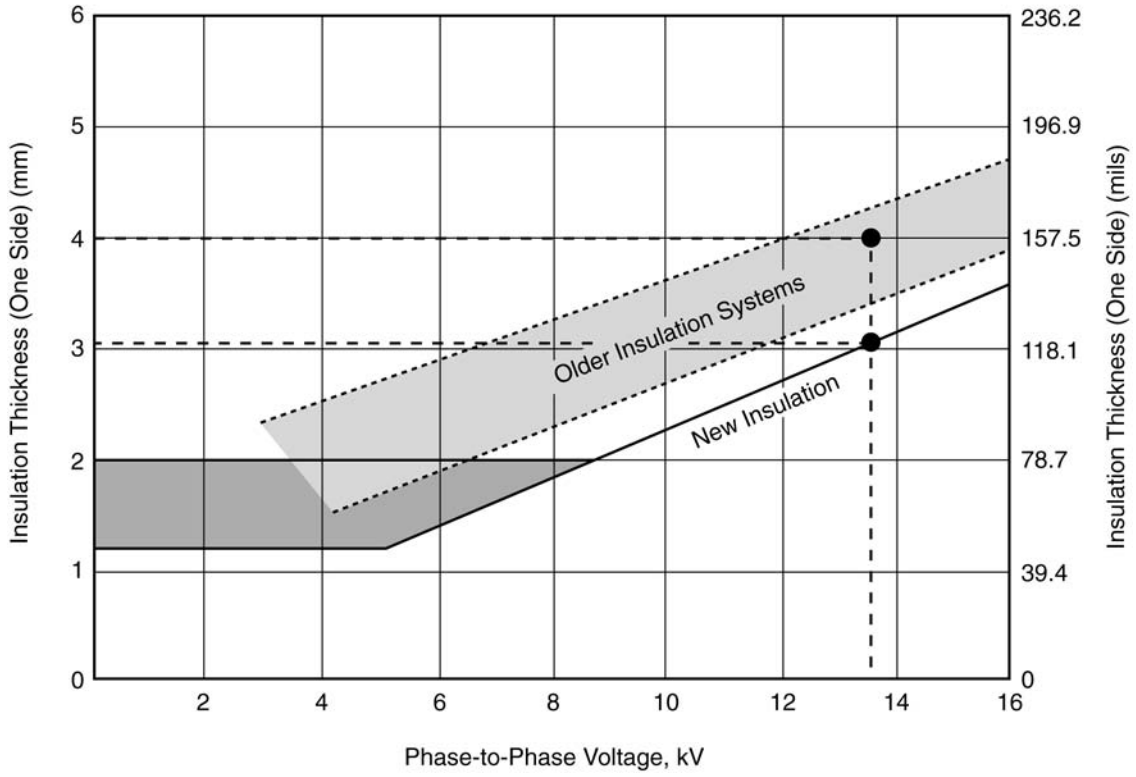

Figure 5-7
Stator Winding Insulation Thickness Versus Rated Generator Voltage

Source: F. Mez, C. Stadelmann, *Moglichkeiten der Leistungssteigerung von Generatoren unter Beibehalt dev Statorabmessungen (Possibilities for Output Increase of Generators without Changing the Stator Dimensions),* Schweizerischer Wasserwirtschaftsverband, Baden, Switzerland. Modified by current knowledge of new insulation systems.

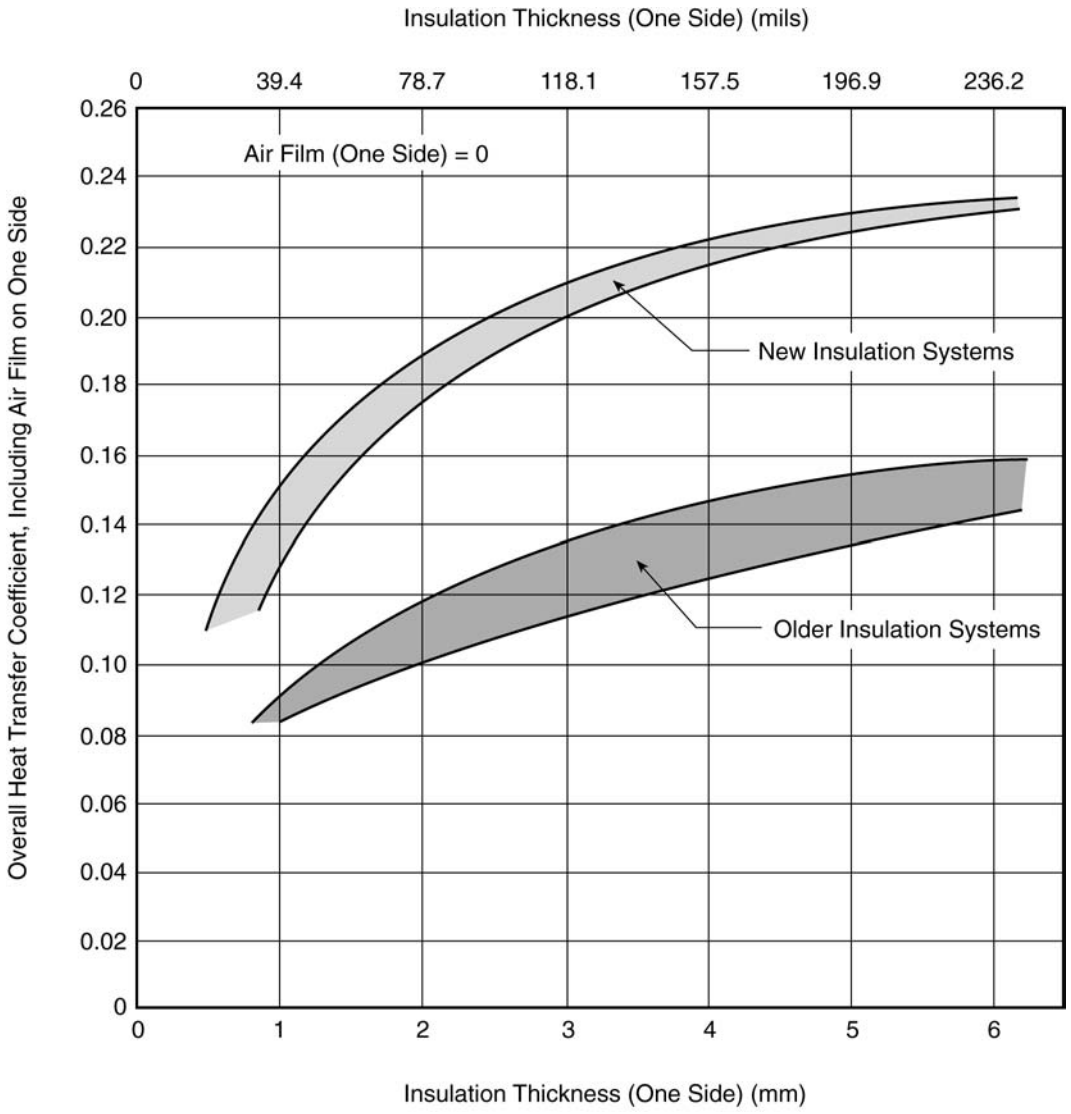

Figure 5-8
Heat Transfer Coefficient for Generator Insulation

Source: F. Mez, C. *Stadelmann, Moglichkeiten der Leistungssteigerung von Generatoren unter Beibehalt dev Statorabmessungen (Possibilities for Output Increase of Generators without Changing the Stator Dimensions),* Schweizerischer Wasserwirtschaftsverband, Baden, Switzerland.

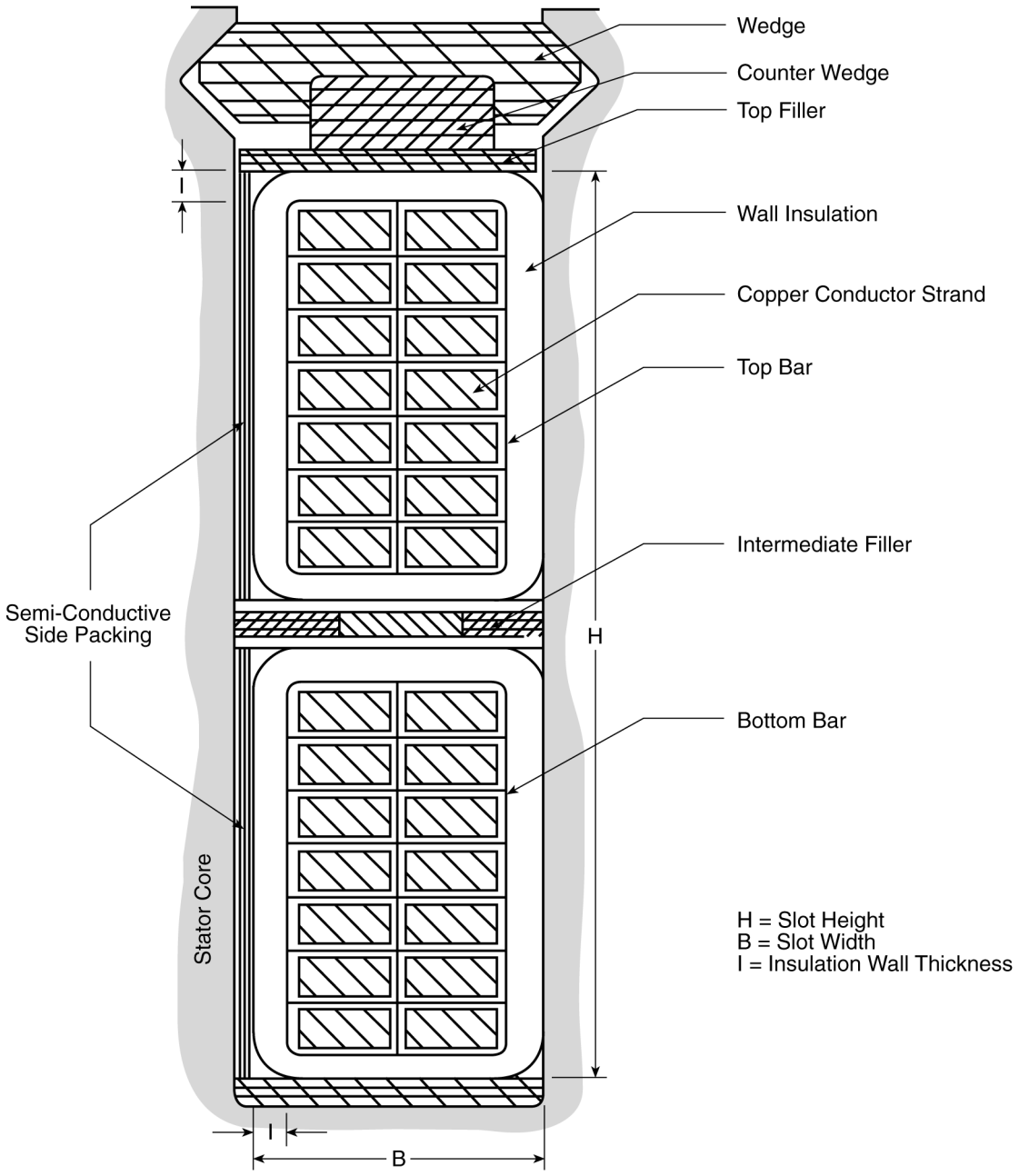

Figure 5-9
Cross Section of Stator Winding

Source: F. Mez, *The Refurbishment of Hydrogenerators, Water Power and Dam Construction*, October 1987. Modified to show side packing.

If the first condition is not met, the change from multi-turn to single-turn windings will require a change of generator voltage. If the unit transformer cannot be adapted (within the range of the tap changer) to accommodate the voltage change, the transformer will have to be replaced and the required change of generator voltage may make the single-turn winding impractical.

As a result, several areas of improvement exist when an older thermoplastic winding is replaced by a modern winding:

- Greater copper cross section in the same slot as a result of the reduced insulation wall thickness
- Higher operating temperature as permitted for modern insulation, thus, higher current loading for a given copper cross section
- Possible additional increase in copper cross section by changing from multi-turn to single-turn winding
- Reduced magnetic induced losses due to Roebel transposition
- If the stator core is replaced, additional slot width and copper area may be realized and the use of Roebel bars optimized

For a feasibility level investigation, a percentage estimate of the uprating potential can be made as follows:

1. Determine the existing bar/coil dimensions in the slot, either from drawings or by measuring a spare winding bar/coil or the slot dimension directly on the machine, as shown in Figure 5-9.

2. Determine the existing insulation thickness by cutting a spare bar/coil or a damaged, removed bar/coil. If this cannot be done, assume that the current winding has approximately the insulation thickness indicated in Figure 5-7 for older insulation systems.

3. Determine the insulation thickness for a new winding from Figure 5-7.

4. Calculate the gross copper cross section of the existing winding and the new winding.

Assuming constant losses, the current (and output) can be increased in proportion to the square root of the cross-sectional area increase of copper.

If the existing winding is of the multi-turn type (to be determined from drawings or by cutting a spare winding) and replacement by a single-turn winding is feasible, an additional increase in copper cross section is possible. Because there is no interturn insulation, the space of the interturn insulation is available for additional copper. An exact determination of the copper cross section would require the winding design to be determined by a manufacturer. However, for the purpose of a feasibility study, it is safe to assume that approximately 5% more copper cross-sectional area can be achieved if the existing multi-turn winding can be replaced by a single-turn Roebel winding.

Increasing the operating temperature of the winding, or temperature rise above ambient, has been mentioned as a way to achieve higher output. However, not only must the winding and insulation withstand the higher temperature, the greater heat (or energy loss) must be dissipated by the cooling air, coolers, and, finally, the cooling water (if applicable). Limitations in the cooling system may prevent using the full temperature increase that is possible for a modern insulation

system. A full thermal network analysis would be required to determine the uprating potential due to a higher operating temperature of the winding. This analysis must be done when rewinding and uprating are actually performed and is beyond the scope of these guidelines. For the purpose of the feasibility study, the user can assume that only half of the possible temperature rise can be utilized, as shown in Figure 5-6. The full temperature rise for 13.8 kV from 60 to 75°C would allow an increase in the current of 13% ($\sqrt{1.27}$ =1.13).

Table 5-6 provides an overview of uprating possibilities and combinations.

Table 5-6
Stator Winding Upgrade Examples

Winding	Existing	New	New
Type	Multi-turn	Multi-turn	Single-turn[2]
Insulation	Thermoplastic	Thermoset	Thermoset
Copper cross-sectional area, %	100	120	125
Current for unchanged losses, %	100	110	112
Current for increased temperature rise, %[1]	Not applicable	113	113
Combined uprating potential due to greater copper cross-sectional area and increased temperature rise, %	Not applicable	117-123	120-125

1. If only half of the permissible rise is utilized, the corresponding current increase is approximately 6.5% (½ $\sqrt{1.27}$ = 1.063)
2. Roebel bars

5.4.4 Stator Core Replacement

Stator core replacement should be considered if the existing stator core is deteriorated or damaged or if a greater increase in output is desired than can be achieved by rewinding using the existing core. Stator core replacement is often performed in conjunction with replacement of the windings. Reinstallation of the old windings in a new core would not fully use the new core.

Modern core steels have less than half the losses of older steel cores. For the same air gap induction, less core material in the teeth is required and larger slots are possible due to improved saturation characteristics. There are no accepted formulas to estimate the amount the slot width can be increased because each case must be considered individually. However, the following guidelines can be used. The capacity of a modified generator with a new stator core and new stator winding should approach the capacity of a new generator with the same dimension and speed. Therefore, the formula used to determine the capacity of a new generator can be used to estimate the capacity of the "rewind and restack" case as follows:

$$S2 = R \times C \times D^2 \times L \times N \qquad \textbf{Eq. 5-2}$$

where:

S2 = apparent capacity of the modified generator, kVA

R = a reduction factor to account for the generator being used. A value of R = 0.90 is recommended; however, this may be optimistic depending on the generator age. Many 1920s and 1930s units may be "less able" due to core steel quantity and mechanical and thermal limitations.

C = the capability factor, take from Figure 5-10, in kVA min/m^3. Use the existing nameplate capacity to determine the capacity per pole, $\frac{S}{2p}$

D = stator bore diameter (m); use existing dimension

L = stator bore height (m); use existing dimension

N = speed in rpm, use existing speed

The result will be the maximum possible uprating potential for the existing generator. Only a new generator can provide even greater capacity. Uprating the generator to this maximum potential will likely require larger coolers, new field poles, and a new excitation system.

Experience with redesigned machines with new stator windings and cores indicates that output improvement between 15 and 50% can be achieved. For more accurate information on uprating potential and cost, manufacturer's quotations should be obtained.

5.4.5 Field Winding and Poles Uprating

The uprating capacity of the field winding and poles is limited by the maximum possible field current and magnetic flux within the permissible temperature rise limits. If the field coils have deteriorated interturn insulation (resulting in "shorted turns"), the possible ampere turns may be further reduced. The presence of multiple adjacent shorted poles is an unacceptable condition for continued normal operation and even more unacceptable for uprated operation. Additionally, magnetic imbalance and induced vibrations are possible. Furthermore, existing shorted turns imply continuing deterioration.

If uprating is to be considered, all field winding and coil components should be restored to an as-good-as-new condition. The high potential testing of the ground insulation, pole drop, and voltage testing of the interturn insulation and other tests listed in Chapter 4, "Performance Evaluation and Condition Assessment," may be helpful in detecting hidden weaknesses.

In cases in which repair of field coils is necessary because interturn insulation failure on several coils is imminent, all coils must be repaired to avoid failure. The need for repair or replacement provides an opportunity to increase the uprating potential because the new coils can be provided with modern, more heat-resistant insulation. If necessary for uprating, the conductor copper cross

section may also be increased. Thus, a full set of rehabilitated field coils, fitted onto the old pole cores, not only increases the reliability but also enables uprating the generator. In cases in which an even higher uprating is required, replacing the pole cores and modifying the air gap are possible in conjunction with a complete redesign and rehabilitation of the generator by a generator manufacturer or an experienced winding supplier.

The expected temperature rise of the field winding must also be confirmed to be within permissible limits. The generator field current increases proportionately with increasing load along the saturation curve of the existing generator, depending on power factor and voltage. Therefore, the field current, I_{f2}, corresponding to the increased rating for the operating power factor voltage as shown in Figure 5-5, is used to verify the temperature rise using Equation 5-3.

$$\Delta t_{f2} = \Delta t_{f1} \text{ x } \frac{I_{f2}2}{I_{f1}2} \qquad \textbf{Eq. 5-3}$$

where:

Δt_{f2} = field temperature rise of the uprated output

Δt_{f1} = field temperature rise of the existing output

I_{f2} = field current at the uprated output

I_{f1} = field current at the existing output

If the existing field coils and insulation are used for the uprated output, the temperature rise of the field winding must not surpass the safe limit for prolonged operation of the field winding. If inspection of the generator condition reveals the existence of deteriorated field winding insulation or of short-circuited turns, the operating temperature rise should not be increased above the existing condition unless the field coils are re-insulated or replaced with coils having improved insulation. Field winding modifications required for a specific uprating condition must be determined on a case-by-case basis.

As part of any uprating, the collector rings, carbon brushes, and field leads between exciter and brushes and on the rotor must be checked and possibly modified or replaced in order to operate at a higher excitation current loading. This can be problematic and requires care for generators in which slip ring connections run through hollow shafts.

5.5 Modernization/Upgrading of Other Generator Associated Equipment and Components

5.5.1 Design of Mechanical and Structural Components

Uprating the generator output requires that the mechanical generator components be analyzed to confirm that they have adequate strength and that the operating stresses do not exceed allowable values under the increased output condition. The components and the design conditions to be investigated are outlined in the Table 5-7.

Table 5-7
Mechanical Components

Component	Design Criteria
Generator shaft	• Maximum output and critical speed • Design case of 180° short circuit on rotor poles
Shaft coupling	• Maximum output • Design case of 180° short circuit on rotor poles
Rotor spider	• Maximum output and runaway speed; fit to shaft, rotor rim, and thrust block • Design case of 180° short circuit on rotor poles
Stator soleplates, anchorage, and iron core support	• Short-circuit torque
Thrust/guide bearing and bearing brackets	• Hydraulic thrust, magnetic forces during faults • Design case of 180° short circuit on rotor poles

In uprating cases where the turbine runner is to be replaced or where the runaway speed will be increased above the existing runaway speed, the generator capability to withstand the increased runaway speed should be investigated. Prior to making any equipment modifications, upgrades, or operating the generator at higher speeds, the generator design, materials, and condition should be evaluated and analyzed by the manufacturer selected to upgrade or modify the generator.

The user is also cautioned that operation of a hydraulic-turbine-driven generator unit at full runaway speed is a severe test and may result in damage to the machine and/or powerhouse structure. Recognizing the relatively small probability of a full runaway occurring over the life of the generator and the potential for damage resulting from a runaway speed test, owners and the International Electrotechnical Commission Publication 545, “Guide for Commissioning, Operating and Maintenance of Hydraulic Turbines,” recommend that runaway speed tests only be performed in exceptional cases.

For preliminary feasibility investigations, the original design calculations can be used to recalculate component adequacy if no component deterioration has occurred. When the original calculations are unavailable, the following guidelines can be used to determine the limit of acceptable peripheral rotor runaway speeds:

- Cast steel rotors manufactured prior to 1935: < 350 ft/s (106.68 m/s)
- Cast steel rotors manufactured prior to 1960: < 460 ft/s (140.21 m/s)

- Laminated rim rotors manufactured prior to 1960: < 540 ft/s (164.59 m/s)
- Modern laminated rotor rims made of ultra high-strength steel: < 610 ft/s (185.93 m/s)

If the runaway peripheral speed exceeds these values, the following actions should be considered:

- Replace the rotor
- Test the instrumented rotor at increased speeds up to runaway speed, while taking all precautions in the event of failure, and calculate impacts of further overspeed
- Perform a detailed investigation of the rotor design and materials by the generator manufacturer selected to upgrade the generator

5.5.2 Modernization of Exciter

Exciter upgrades are often initiated for the following reasons:

- Lack of spare parts for the existing exciters (obsolescence)
- Automation of the hydro plant requiring exciter upgrades (modernization)
- Requirement to improve plant performance characteristics

In most cases, rotary exciters (because of their age) tend not to be supported by manufacturers. In addition, spare parts are difficult to find, which forces their replacement. Static exciters have the benefit of higher efficiencies than rotary exciters. The improved performance of power electronics, analog or digital excitation controls, can widen the output range or improve the response time of the unit that may increase the plant's value to the system it supplies.

A digital excitation control system can provide more features than its analog counterpart. In addition, the digital systems are drift free, which is an improvement on the analog excitation system in which gains and time constants tend to drift over time.

Where improved response is not of value to the system, a more cost-effective upgrade in lieu of a full static excitation system may involve the installation of a static pilot exciter in conjunction with the existing rotary exciter. The static pilot exciter replaces the existing voltage regulator but continues to use the main rotary exciter.

Where rotary exciters remain in use, brushgear is being replaced by constant pressure brush holders as an upgrading measure.

Excitation systems are usually oversized with respect to the generator's requirements. Therefore, the generator can be uprated in many cases without being constrained by the exciter. However, in other generator uprating cases, the existing exciter output may be insufficient and the exciter or a component of the excitation system limits the generator uprating potential. Additionally, the existing excitation system AVR may not be adequate to meet the generator uprating requirements. See Volume 7 for information on AVRs.

The tests performed on the excitation system may result in any of the following findings:

- Existing excitation system current rating, temperature rise, and cross-sectional cable area are adequate for uprated generator operation
- Dynamic performance of the existing excitation system is satisfactory for the existing and uprated generator operation
- Existing excitation system or components are a maintenance problem

If the assessment indicates that the excitation system must be replaced, the modernization alternatives are as follows:

- Replace the present dc exciter machine (rotating) with:
  - Brushless rotating excitation system consisting of static ac exciter with rotating rectifiers
  - Static excitation system comprising power electronics controlling the dc excitation current derived from the main generator terminals
- Rehabilitate an existing brushless excitation system with uprated components or entirely replace the system

Rebuilding of rotating exciters is usually less expensive than replacing the AVR and the rotating exciter. Furthermore, maintenance requirements on the commutator brushgear are high, and carbon dust from the brushes can form a conducting film on machine parts that causes surface tracking problems. The selection of a brushless or static excitation replacement system is best determined on a case-by-case basis. The exciter performance requirements may make replacement with a static excitation system preferable to replacement with a brushless system. The advantages and disadvantages of the alternatives are outlined in Table 5-8.

Table 5-8
Comparison of Rotating Versus Static Excitation Systems

System	Advantages	Disadvantages
Brushless with rotating diodes	No rotating contacts Immune to system disturbance Compact size	Poor maintenance capability No fast response de-energization Unable to reverse fill Slower response than static; however, faster than rotating dc exciter
Static	Generally lower cost Rotating machine and extension shaft are not required Fast response capability Fast de-energization High technological maintenance capability Lower downtime rate Field circuit breaker can be replaced by an ac breaker	Slip rings, brushes Excitation transformer required Large bulk size Vulnerable to system disturbances Electronic specialist required for maintenance High transient voltage straining the field winding at every forced overvoltage change

5.5.3 Braking System

Older machines generally used asbestos brake pads. As a result of environmental and health concerns, many utilities are now retrofitting with pads manufactured from fiberglass materials. However, because fiberglass pads have a different coefficient of friction than the asbestos ones, the hydraulic application pressures must be adjusted accordingly.

In addition, the installation of a brake dust collection system may also be advisable. Although this system does not enhance braking performance, it will reduce the contamination from the brake pads that accumulates on the insulation systems for sections such as end turns and ring buses. Typical systems include shrouds, ducting, filters, and blowers. The system is switched on upon braking action.

5.5.4 Fire Protection

5.5.4.1 General

The modern standard for fire protection is more advanced than what was considered acceptable in the past. Fire protection technology has improved, but the greatest improvement has been in the attitude toward fire protection and the realization of the need to protect against fire.

Upgrading an existing hydroelectric station to a modern standard can be a daunting task. The layout of an existing station might make it costly or even impossible to install all of the modern fire protection features.

When reviewing options for modernization, the benefit to be gained should be balanced against the cost incurred by the upgrade. Therefore, stations that will make good candidates for modernization are those with the following:

- High value
- Large annual energy production
- Long remaining service life
- Limited fire protection installed

The objective of modernization is to significantly improve on the existing level of fire protection and reduce the potential for extreme fire losses.

The options for modernization included in this section were originally developed for medium-to-large hydroelectric stations (minimum capacity of 100 MW); therefore, some of the options might not be practical or cost-effective for small stations.

5.5.4.2 Fire Detection and Alarm Signaling

If there is no existing fire detection and alarm signaling, or if the existing system is ineffective, the best option is modernization. A suggested modernization would be to install a fire detection and alarm signaling system. The system could include the following features related to generator fire protection:

- All components listed by a recognized testing agency
- Operate on low-voltage (24-volt) dc power
- A main station fire alarm panel
- Sub-panels (or “unit fire alarm control panel”) for each unit that can stand alone if the main panel is disabled (sub-panels should be relay-based)
- Detector sensitivity readout/printout for the main panel
- Laptop computer field programmability for the main panel

- Remote monitoring dial-up capability for the main panel
- Interactive video display terminal with color graphics software for the main panel—installed in the control room—to allow the fire to be located
- An exterior-mounted remote annunciator panel connected to the main panel, with alpha-numeric display and control pad, at the main entrance to the powerhouse building to enable the location of the fire to be identified
- Supervision of all fire protection valves, fire pumps, fire detectors, and fire suppression systems (the generator fire suppression system should be supervised by the unit fire alarm control panel)
- Unit shutdown by the protection and control system through the unit fire alarm control panel upon detection that the deluge system has operated
- Duct-type smoke detectors and thermal detectors in the generator
- Linear beam smoke detectors at the powerhouse ceiling above the units
- Ability to control the HVAC system and the smoke control system to prevent the spread of smoke in the event of a fire
- Audible and visual alarm signaling throughout the building
- An emergency power supply capable of supplying 24 hours of supervisory operation plus a set time of full alarm operation (a minimum of 30 minutes is recommended)

5.5.4.3 Fixed Fire Suppression

If there is no existing fire suppression system or if the existing system is ineffective or has other associated problems, consider the installation of a water-spray deluge system as an option for modernization. Water-based systems have demonstrated their effectiveness in extinguishing generator fires.

When reviewing options for modernization, keep the following important points in mind:

- Fire suppression systems should be supervised by the unit fire alarm control panel or the station fire alarm panel for discharge and tampering. In most cases, the operation of the fire suppression system should be interlocked with the fire detection system.
- Install both automatic and manual activation capabilities. Manual activation should be readily identifiable, easily located, and prevented from accidental operation.
- Fire suppression systems should have a means of manual shutdown located in a conspicuous location and readily identifiable.
- The system must have lockout capability for testing, commissioning, and performing maintenance.
- New fire protection piping must be seismically restrained.
- To prevent the creation of voltage potential and an electrocution hazard, new fire protection piping must be bonded and grounded.

- Consider a dedicated pressure switch connected directly to the unit protection and control that senses the activation of the fire suppression system and provides unit shutdown. The switch is not dependent on the unit fire alarm control panel.
- New water-based systems should be installed in compliance with NFPA 15, "Standard for Fixed Water Spray Systems for Fire Protection."
- A water-based system should be designed to provide a spray of water droplets directly onto the insulated portions of the upper and lower winding structures, including the stator windings, stator terminals, circuit rings, winding endheads, field windings, and damper windings.
- A new water-based system should be set for cycling operation; a range of 5 to 15 minutes is generally recommended. After this period of operation, the system should reset and have the ability to activate again if the detectors identify a fire condition.
- Install a test loop that is piped directly to drain to permit testing.
- All valves for the fire protection water supply should be supervised by the station fire alarm system. In addition, the fire protection water supply should not be affected by shutoff of domestic water or other service water supply. Pressure-reducing valves and other components must operate correctly so that they do not impair the ability of the system to provide required flow and pressure. The system must be capable of providing water to multiple systems.
- If the station has a low head and the water supply system cannot provide the necessary pressure and flow for fire suppression, a fire pump will be required to boost water pressure.
- If a new fire pump is required, it should be installed in compliance with NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps." All components should be listed and labeled by a recognized testing agency for use as a fire pump.
- A new fire pump should be installed inside an enclosure having a fire separation with a 1-hour fire-resistance rating ("1-hour fire separation") to protect it from a fire in the adjacent floor area.
- If a new diesel-powered pump is installed, special consideration must be given to diesel fuel storage to ensure that it is not a fire hazard in itself. Diesel fuel should be stored inside a liquid-tight room with a 2-hour fire separation enclosure.
- The power supply cables to the electric fire pump should have a 1-hour fire-resistance rating or should be enclosed in construction having a 1-hour rating. Provision must also be made for emergency power supply in the event that station service is lost.
- CO_2 systems are no longer as common for new installations as they were previously. If a CO_2 system is desired, it should be installed in accordance with NFPA 12, "Standard for Carbon Dioxide Systems." A sufficient volume of agent must be available to extinguish a fire. NFPA 12 requires that systems protecting dry electrical equipment be designed to a CO_2 concentration of 50% by volume; this figure does not include the amount required for extended discharge during generator rundown.
- Piping and fittings must be of the correct material as specified by NFPA 12. Fittings and piping should be able to withstand the burst pressure specified by NFPA 12.

- To reduce the life safety risk associated with CO_2 systems, these systems should be equipped with pre-discharge warning alarms and provision for disablement to prevent unwanted discharge for situations in which personnel are working on the system or in the protected space. Furthermore, rescue procedures must be developed for times when personnel are working in the protected space. Self-contained breathing apparatus must be available for rescue purposes. Portable air-monitoring equipment and breathing apparatus must be available to allow personnel to check that the space is safe for re-entry.
- CO_2 systems should be equipped with pre-discharge warning alarms and the capability to disable the system so that personnel can work on the system or in the generator enclosure. An abort switch for manual shutdown is also required.
- A generator protected with a CO_2 system must be enclosed to prevent loss of agent and reduction of effectiveness. Although it will generally not be possible to completely prevent leakage, large openings and holes in the enclosure should be sealed. If these openings cannot be sealed, an additional amount of CO_2 gas above the calculated value will be needed to offset leakage.

5.5.4.4 Enclosure

If the units are not enclosed, enclosure is an option for modernization. However, this upgrade might not be cost-effective or practical in smaller stations or where the units were intended to be open to facilitate easy access. In these situations, more emphasis should be placed on other fire protection measures.

Although the number of options for modernizing a generator enclosure is more limited than for other systems, the following items should be kept in mind:

- If there is no enclosure around the generator, is it practical to construct such an enclosure? If there is a partial enclosure or the existing enclosure is missing key features, such as fire stop systems for cable and pipe penetrations, consider rebuilding the enclosure to a modern standard.
- If an enclosure is desired, a fire separation with a minimum 2-hour fire resistance rating is recommended.
- Doors and access hatches should be equipped with closures that have a minimum 1.5-hour fire protection rating. It might not be practical to protect all openings.
- Penetrations through the enclosure for cables, cable trays, conduits, ducts, pipes, tubing, and other services should be provided with listed fire stop systems that have a minimum 1.5-hour "F" rating. It might not be practical to protect all penetrations.
- If an enclosure contains asbestos, consider safely removing the asbestos and rebuilding the enclosure using modern materials.

5.5.4.5 Smoke Control

Many of the older hydroelectric power stations in North America were constructed with limited ventilation and no means of smoke control. Therefore, these systems are prime candidates for modernization. Smoke control is of particular concern in underground power stations.

A smoke control design should incorporate the entire powerhouse and not just the generator enclosure because the smoke from a generator fire will affect the entire powerhouse. Smoke control is a complex issue that requires specialized knowledge to design an effective system.

When considering options for modernization, the following important points should be kept in mind:

- Any new systems should be designed and installed in accordance with NFPA 90A, "Installation of Air Conditioning and Ventilating Systems," NFPA 204M, "Guide for Smoke and Heat Venting," and NFPA 92A, "Recommended Practice for Smoke Control Systems."
- To vent smoke, the affected area must be pressurized with fresh air, and contaminated air must be extracted. Due to the buoyant nature of hot gases, air extraction is best performed at the ceiling of the affected space. In general, fresh air should be introduced at a low elevation.
- Any modernization of smoke control should provide the capability for both manual and automatic operation (through the fire alarm system).
- Existing air-handling systems may be incorporated into a smoke control system if they are approved for use in such a system. Smoke control equipment must be able to withstand higher temperatures than ordinary air-handling equipment.
- Duct-type smoke detectors might be required in air supply passages to indicate the presence of smoke. These detectors will be part of the fire alarm system.
- The operation of the smoke control should be integrated with the main fire alarm panel.

5.5.5 Generator Cooling

Generator cooling modifications can often be used to achieve generator uprating or may be necessary for handling the additional heat load of an uprated generator.

Methods for reducing the operating temperature of the generator components include increasing cooling airflow and velocity and improving cooling air distribution. Reduction of the generator inlet air temperature can be accomplished by increasing the cooling water flow or increasing the size of the air coolers. Safe operation at the upper temperature rise limits is most likely when starts, stops, and load changes are minimized. Consequently, in some cases, cooler modifications that result in lower cooling air inlet temperature can result in higher output operation at the same absolute generator temperature.

Cooling can also be improved by reducing component temperature rise by decreasing the heat transfer resistance between the winding copper and cooling air. Modern stator winding insulation contributes to the desired heat transfer reduction. The thermal resistance of the insulation is reduced by 50% and the winding surface temperature is increased, which, in turn, improves the

heat transfer to the cooling air. The use of cooling to further reduce the temperature rise is possible only by increasing the cooling air velocity and improving the cooling air distribution. Although the cooling airflow of generators is normally more than adequate, there are cases where fan design and cooling airflow are minimal or insufficient. In such cases, fan and cooling airflow improvements may result in a noticeable increase in the uprating potential of a generator. Special consideration must be given to end turns, circuit rings, and terminal equipment.

The other area of focus is the potential to save cooling water that could be used for generation. Cooling water designs can be conservative, keeping generator temperatures within normal limits even with the loss of one air cooler. Modernization could include the installation of modulating control valves that adjust the cooling water flow rate to maintain a constant generator temperature. This should lead to optimization of cooling water, with the added benefits of reducing thermal cycling/stress on the generator. Instead of setting the flow rate for the worst-case scenario, which means the highest requirements, the cooling water rate will be adjusted based on unit loading and ambient temperatures. Annual cooling water requirements should decrease.

Another option to consider is automatic shutoff of the cooling water on unit shutdown. Implications of this change in unit stopping sequence should be thoroughly investigated.

Although plants with excess water would achieve no annual benefit from cooling water conservation, the reduction in unit temperature fluctuations may be attractive from a unit life perspective.

5.5.6 Generator Circuit Breaker

The modernization alternatives considered will depend on the condition and age of the equipment determined during the component assessment stage, the adequacy of the component ratings based on the system electrical analysis, the desire to automate for remote control operation, and the importance of the power generated at the facility to the rest of the system. If the existing component is old and obsolete, upgrading to improve equipment performance and reliability should be considered. Uprating the terminal equipment may also be necessary, depending on the extent of the electrical system uprating. The following are possible equipment modernization options:

- Replace the existing obsolete switchgear. Obsolete circuit breakers, such as those containing bulk oil circuit breakers, may continue to be operational; however, these typically have high maintenance requirements and present considerable fire and environmental hazards. Switchgear components containing PCB liquids, such as Askarel/Pyranol/Inerteen, are environmentally hazardous if a fire should occur and should be replaced.
- Install modern switchgear with higher capacity. If the existing rating is insufficient to meet the proposed uprating, replacement with new, higher capacity switchgear is necessary.
- Repair or replace components to correct insulator problems. Excessive accumulated pollution on outdoor insulators can cause flashover. Open busbars are vulnerable to animals. For example, birds can cause problems through nesting, deposition, and bridging. The use of indoor or enclosed equipment can reduce these problems.

- Convert to remote operation. Manual operation of the disconnect switches requires the presence of an operator. Disconnect switches can be converted to motorized remote-controlled devices. Remote-control switchgear conversion can be accomplished to facilitate switchgear operation or in conjunction with automation of the plant.

5.6 New Generators

This section provides a simplified method for determining the major outline dimensions and capacity of new generators. The following procedure can be used to select a replacement generator operating at the same speed that will fit the existing generator barrel. The latter condition can be satisfied by choosing the same stator bore diameter for the replacement generator, although consideration of diameter increases may be warranted in older generators.

In most cases, the dimensions of the existing generator barrel will allow a slight increase in core length. This can be confirmed by evaluating the generator barrel height. In old vertical generators, the thrust bearing was typically on top of the generator and was supported by a heavy cast steel bracket. The replacement generator may be designed with a combined thrust/guide bearing located below the generator. A single guide bearing may or may not be located above the generator. As a result, the new generator will have a much lighter top bracket, if any. Consequently, the dimensional limitations will often permit an increase of 10–20% in active core length. With the higher capability factor of modern generator designs, a capacity increase of more than 50% can often be achieved. Therefore, installing a new generator in the existing generator barrel will usually meet or exceed the uprating potential of a turbine in the existing powerhouse space and foundation.

In simple terms, the capacity, S, of a generator can be defined as a function of stator bore diameter D, core length L, and speed N. These factors are combined with a capability factor, C, as follows:

$$S = C \times D^2 \times L \times N \qquad \textbf{Eq. 5-4}$$

where:

S = capacity in kVA

C = capability factor kVA min/m^3 (see Figure 5-10)

D = stator bore diameter in meters

L = stator core length in meters

N = speed in RPM

Typical values of the generator capability factor (kVA min/m^3) for modern generators are shown in Figure 5-10 as a function of power divided by the number of poles (S/2p). In general, generators designed prior to 1970 were conservatively designed with low capability factors. As a result, pre-1970 generators may have twice the uprating potential of less conservative designs.

This same formula can also be used to estimate the dimensions and capacity of a new generator in a new or modified powerhouse, where the dimensional restrictions do not exist. The speed is determined by the turbine. Next, the stator bore diameter has to be determined, and the core length follows as a function of capacity and capability factor.

To minimize the rotor weight for a given inertia, the largest possible rotor diameter should be used. This diameter, however, will be influenced by the mechanical strength of the steel available for the rotor rim lamination. The maximum peripheral velocity of the rotor at full runaway speed should be no greater than 575 to 600 ft/s (175.26 to 182.88 m/s).

The procedure is as follows:

S = capacity in kVA, selected for the new generator

N = speed in RPM, determined by the turbine

NR = runaway speed, determined by the turbine

The largest possible stator bore diameter D in meters is determined by the following:

$$D < \frac{60 \text{ x } 575 \text{ x } 0.3}{\Pi \text{ x } NR} \qquad \textbf{Eq. 5-5}$$

Capacity per pole: S/2p

$2p = 700/N$

Then choose the capability factor, from Figure 5-10.

Core length L: $L=S/(C \text{ x } D^2 \text{ x } N)$ **Eq. 5-6**

The owner's consultant can use the above preliminary size and capacity calculations to further study the potential benefits of replacing the generator stator, rotor bearings, and coolers; the excitation system; and the terminal equipment.

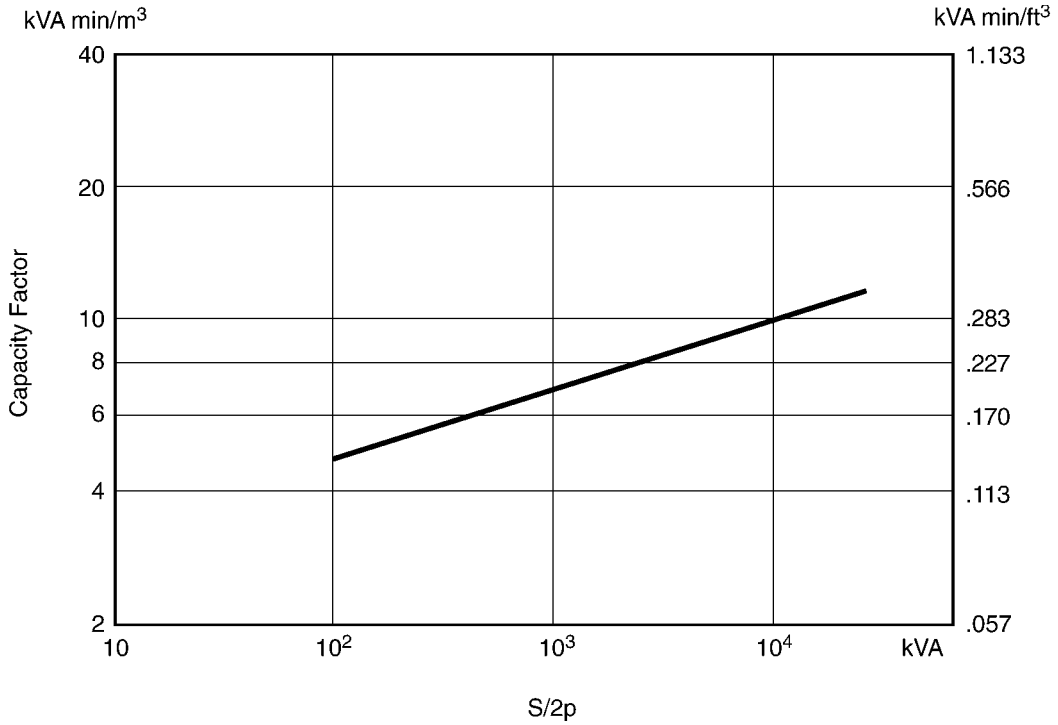

Figure 5-10
Capability Factor for Synchronous Generators Having More Than 16 Poles and a 0.9 Power Factor

5.7 Development of Overall Plant Modernization Alternatives

Modernization Opportunities (Step 5-2, 3, 4, 5, 6 Volume 1)	Benefits of Modernization (Step 5-2, 6, 7, 8 Volume 1)
Further Studies Required	
Impacts of Modernization on Other Equipment	**Other Equipment that Limits Modernization**
Timing of Modernization	Risk Evaluation of Modernization
Modernization Opportunities Selected for Input into Table 4-6, Volume 1	

5.7.1 Introduction

This volume has focused on electromechanical equipment. This section assists the user in determining the effects on the entire plant of modernizing electromechanical equipment. It should be used in conjunction with other technical Volumes 2, 4, 5, 6, and 7 to produce the realistic LEM alternatives for the generator.

5.7.2 Developing Modernization Plans

Modernization plans generally increase plant capacity. Where feasible, capacity increases can be accomplished by increasing component capability, operating head, flow rate, and/or overall efficiency.

Because plant components often have different ratings or design margins, the capability of each component in the plant must be considered before uprating the component and plant capacities. Therefore, alternative uprating plans differ in the number of components for which uprating is required. The higher the uprating capacity, the more components affected—with proportionally higher costs.

The design criteria that determine the capability of electrical components, such as the generator, switchgear, transformer, and transmission line, are the apparent output or apparent capacity in kVA and not the active capacity measured in kW used to denote unit and plant capacity. Power factor (cos Φ) is used to convert between apparent and active capacity where kVA x cos Φ = kW. The power factor relationship determines the capability of the equipment to generate, transform, or transmit reactive power in addition to active power to meet the grid system requirements.

Older hydro plants were often developed in remote locations and connected to load centers by long transmission lines that required relatively high reactive power capability. Consequently, the rated power factors for old hydro generators are often relatively low and are in the range of 0.85 to 0.75.

Today's electrical grid system is different, and the need to generate and transmit reactive power from the hydro plant may be much lower than when the plant was originally built. Therefore, the power factor requirement of the plant should be investigated in conjunction with modernization and updated if possible. Subsequent modernization plans should be based on the updated power factor in calculating electrical equipment active power (in MW). Quite often, limiting the power factor range to 0.90 to 0.95 can allow a 10–20% increase in active power capacity of the electrical equipment without modification.

Two approaches can be used in developing realistic plans to uprate a plant: eliminating bottlenecks and evaluating the condition of critical plant components.

5.7.3 Uprating by Eliminating Bottlenecks

Eliminating bottlenecks, or limitations on a plant's output, considers the existing and uprating potential of the following major components that determine the plant capacity:

- Intake and trashrack
- Headrace canal or tunnel
- Penstock(s)
- Turbine(s)

- Tailrace canal or tunnel
- Generator(s)
- Transformer(s)
- Transmission lines

The cost of other affected components and auxiliaries such as the governor, valves, and switchgear would be added to the cost of the appropriate alternative. Usually, these costs are less significant than those for the major components.

Because of differences in design criteria among components, the uprating potential of a plant or a specific component typically occurs in steps that are not linear. Each specific component change results in an increase in plant potential that is independent of other components.

Some examples of step increases are a new runner that would increase the turbine capacity or a generator rewind that would increase the generator capacity. Replacing the existing component with a component having a higher rating would achieve the maximum uprating potential; however, this is usually limited by space constraints imposed by the powerhouse or equipment.

In developing the initial uprating plans, the technical uprating options for each major component should be determined independently, neglecting cost considerations. The methods and information needed to determine the component uprating options are provided in Volumes 2–7 of these guidelines.

Tabulating the available options in a list, as in Table 5-9, or in a diagram, as in Figure 5-11, shows the interrelationship of the various alternatives and assists in identifying the optimal uprating plan. The bottleneck method can be demonstrated by Figure 5-12, which shows how uprating one component affects successive components. The existing capacity for each component is indicated in the bar graph. As shown, the existing plant capacity is “generator limited” to Level A because all other components have higher capabilities. Installation of a new stator winding would raise the generator capability above the existing turbine capacity. Achieving the maximum turbine capacity (Level B) would also require improvement of the intake and tailrace. The existing capabilities of the other components are sufficient to support operation at Level B.

Uprating the plant to Level C would require uprating the penstock by sandblasting and painting, rehabilitating the canal or tunnel, uprating the turbine with a new runner, and uprating the generator with a new stator winding, core, and exciter. Full use of a new turbine runner (Level D) would also require a new penstock.

Level E, the maximum uprating potential of the plant, is limited in this example by the maximum uprating potential of the tailrace. The tailwater could conceivably be limited in width by space conditions and in depth by turbine runner cavitation considerations under low flow. Uprating to Level E would also require lining the canal or tunnel.

Table 5-9
Uprating Options for Modernization Plans

Components	Existing Capacity Level (%)	Uprating Steps and Resulting Capacity Level Increase			
		Level 1	Level 2	Level 3	Level 4
Turbine	110	New runner, rest of turbine unchanged; capacity level 125%	New turbine, same speed as existing one; capacity level 140%	New turbine, higher speed in accordance with possible runner setting level; capacity level 165%	
Generator	100	New stator winding; capacity level 115%	New windings, iron core, poles, and excitation; capacity level 135%	New generator, same speed as existing unit; capacity level 160%	New generator of higher speed corresponding to turbine, capacity level 180%
Penstock	115	Sandblasting and repainting; capacity level 125%	New penstock for Turbine Discharge 1; capacity level 450%	New penstock for Turbine Discharge 2; capacity level 165%	

Source: Source: *Electric Light & Power*, March 1987, pg. 25

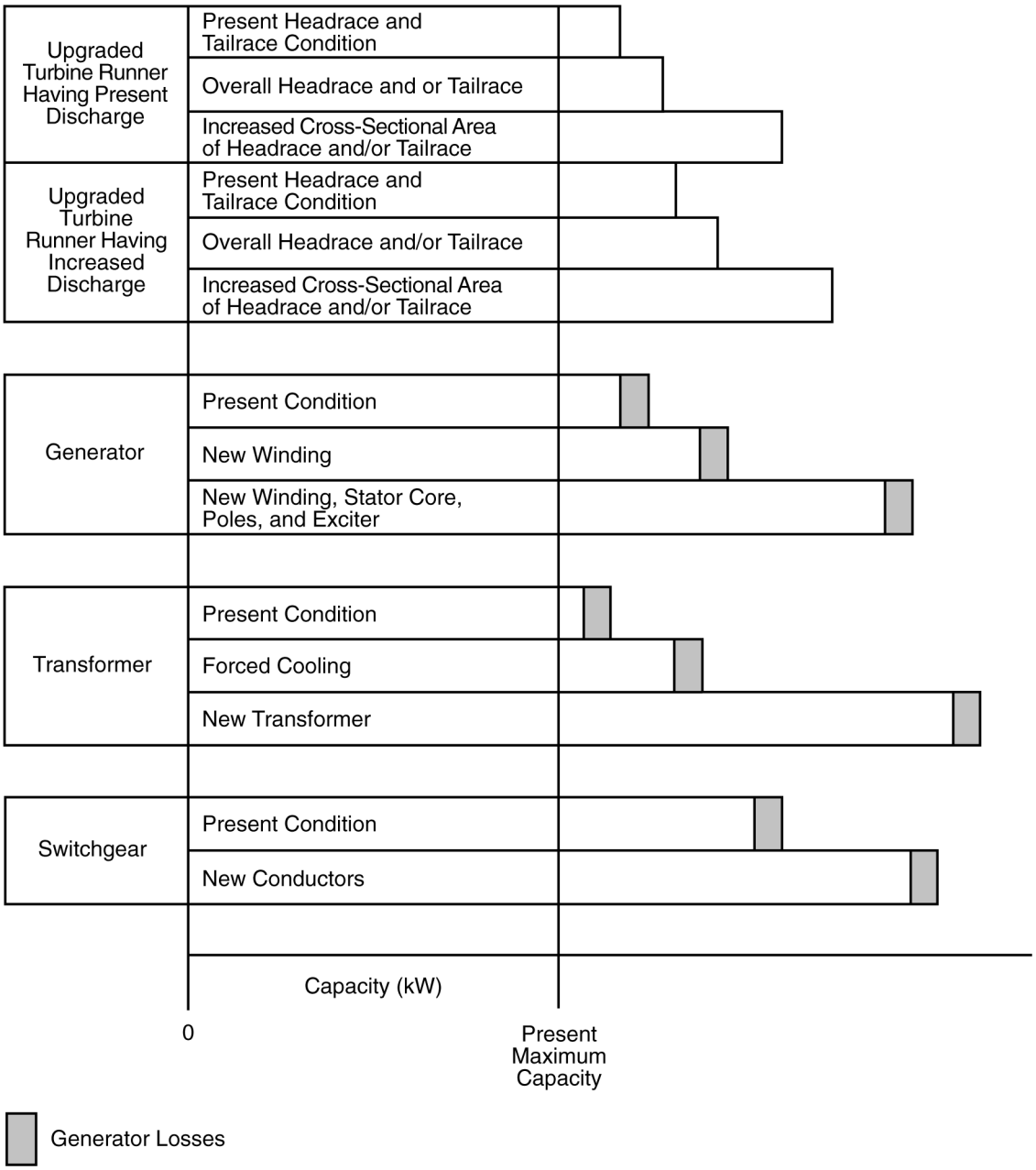

Figure 5-11
Alternatives to Increase Unit and Component Capacity

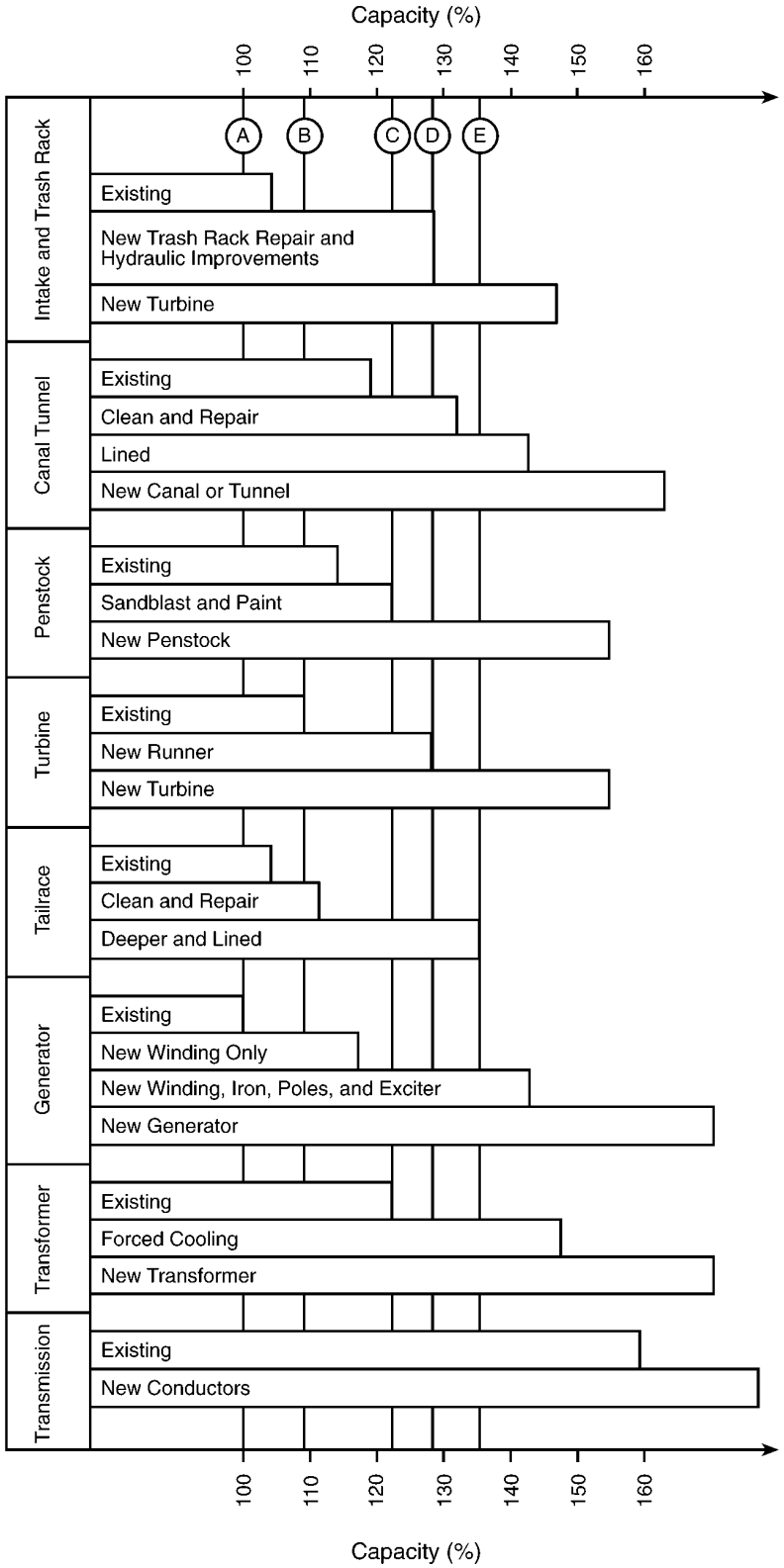

Figure 5-12
Developing Uprating Plans – Elimination of Bottlenecks

Source: *Electric Light & Power,* March 1987, pg. 25

5.7.4 Uprating by Identifying Deficient Components

A second approach to developing potential uprating plans is to identify deficient components. Although the bottleneck approach concentrates on components that limit plant capacity, this approach concentrates on unreliable components identified as being in critical condition during the screening process.

This more direct approach to identifying modernization plans can be used if the condition and reliability of the major components are in need of rehabilitation. In this method, a survey and checklist are prepared for each deficient piece of equipment. Included in the checklist are those components in poor condition, the potential capacity increase of rehabilitation alternatives, and those components affected by the various potential component replacements.

An example of this method is shown in Table 5-10, using the turbine as the deficient component. As shown in the table under Option Plan A, Refurbish Only, a capacity increase of 0–5% is possible by refurbishing the turbine, and no other components are affected. Option Plan B includes runner replacement and a potential capacity increase of 5–30%, but also requires changes to the components indicated in the column. A checklist to assist in determining the interrelationships of components is provided in Figure 5-13. After the components that limit power plant uprating are identified, several alternatives can be developed to achieve the desired overall plant improvements.

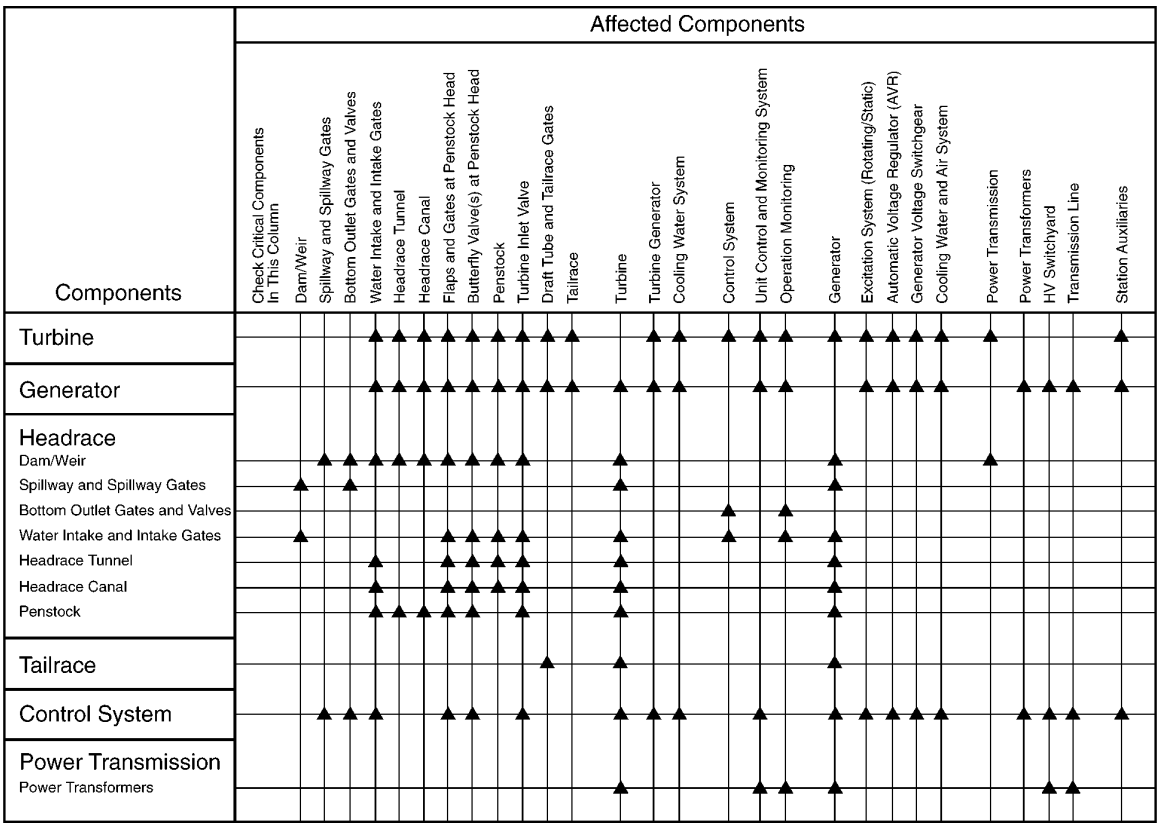

Figure 5-13
Checklist to Determine Affected Components

Table 5-10
Overall Modernization Plans Based on Turbine Upgrading Options

Component	Typical Capacity Increase (Uprating) Ranges and Typical Upgrade Requirements on "Affected Components"			
	Option Plan A	**Option Plan B**	**Option Plan C**	**Option Plan D**
Turbine	Refurbish only	Runner replacement	New turbine internals	New turbine in existing powerhouse
Typical capacity uprate	0–5%	5–30%	20–50%	30–100%
Intake trashrack	Not affected	Refurbish or minor improvement	Major improvement or new	New
Canals	Not affected	Refurbish or minor improvement	Major Improvement or new	Major improvement or new
Penstock	Not affected	Refurbish	Refurbish	New
Generator	Not affected	Rewind	New	New
Transformer	Not affected	Forced cooling	New	New
Transmission line	Not affected	Not affected	Larger conductors	Larger conductors

5.8 Input to Modernization Plan

The final task in the initial selection of modernization activities is to input them into the LEM plan to determine their impact on plant economics. Volume 1, Chapter 4 details the methodology for incorporating identified opportunities into the LEM plan. This is an important step in the iterative process of selecting life extension and modernization activities because it will assist in determining whether the benefits of modernization justify the additional expenditure over the life extension alternative. The information on the *pro forma* "Equipment Modernization Opportunities" worksheet (see Table 5-1), completed for each piece of electrical equipment, should provide all of the necessary information for the LEM plan at this pre-feasibility stage.

After initial financial and economic results are available for the preliminary LEM plan, further studies are required to confirm that the selected modernization opportunities are feasible both technically and economically. Further inspection, testing, and studies for the feasibility stage of analysis are described in Chapter 7 of this volume, "Feasibility: Optimization of Alternatives."

6
ESTIMATE OF COSTS AND BENEFITS

6.1 Introduction

The costs and benefits of possible LEM activities for electromechanical equipment are important factors in any decision regarding the future of a plant. This section provides guidance for overview level cost estimates, which can be used in early development of the LEM plan.

Care must be taken in using the results from generic curves, tables, and processes such as those given in these guidelines, because these results are only approximations. Each plant and each individual unit has its own unique situation that requires consideration before using the information provided in this section. The LEM plan process is iterative and accordingly the accuracy of estimates should improve with each iteration. Estimating considerations are described in Volume 1, Chapter 2.3.5.

All prices used in this section are in year 2001 U. S. dollars (US$). Various indices are available to escalate dollar values for future years, including:

- Handy-Whitman Index of Public Utility Construction Costs
- Bureau of Reclamation Cost Index

6.2 Generator Costs

The costs associated with generator life extension, modernization, and/or uprating depend on many factors such as the design of the original generator, extent of the uprating, plant location relative to manufacturer's service shop, prospective contractor shop workloads, material costs (copper prices), and the extent of field work required. As a result, bid prices can vary by as much as 100% and only general cost guidelines can be presented here.

6.2.1 Unmodified Generator

There are no direct costs associated with the uprating of generators with original asphalt stator windings in good condition and capable of increased output because equipment modifications are not required. The only costs would be associated with generator testing and an uprating evaluation. Likewise, there are no direct costs associated with the uprating of generators with recently rewound modern epoxy stator windings in good condition and capable of increased output.

6.2.2 New Generator

The cost of a new horizontal or vertical synchronous generator can be estimated from Tables 6-1 and 6-2, which provide sample costs from recent generator supply contracts. The costs in Tables 6-1 and 6-2 are based on generators with the following characteristics and scope of supply:

Voltage	13,800 V
Power factor (cos. phi)	0.9
Flywheel effect	Within normal limits
Runaway speed	Within normal limits
Altitude	Less than 3000 ft (914 m)
Scope of supply	Stator, rotor, shaft, closed circuit air cooling equipment, bearing cooling and lubricating equipment, thrust bearing, two guide bearings, bearing brackets, braking and jacking equipment, and static excitation system with AVR
Terms of supply	Supply cost only

Table 6-1
Horizontal Units

Capacity kVA	Power Factor	Voltage kV	Number of Poles	Cost per Unit US$million	kVA/pole	Cost/(kVA/pole) US$
9,500	0.9	13.8	18	1.1	528	2,084
14,200	0.9	13.8	22	1.43	645	2,217
16,500	0.9	13.8	16	1.53	1,031	1,484
16,500	0.9	13.8	16	1.70	1,031	1,648
17,800	0.9	13.8	14	1.10	1,271	865

Table 6-2
Vertical Units

Capacity kVA	Power Factor	Voltage kV	Number of Poles	Cost per Unit US$million	kVA/pole	Cost /(kVA/pole) US$
19,000	0.9	13.8	20	1.60	950	1,684
31,500	0.9	13.8	22	2.80	1,432	1,955
31,700	0.9	13.8	20	4.20	1,585	2,650
38,100	0.9	13.8	24	2.90	1,588	1,827
38,500	0.9	13.8	26	3.20	1,481	2,161
45,300	0.9	13.8	24	3.50	1,888	1,854
67,000	0.9	13.8	56	3.20	1,197	2,674
67,000	0.9	13.8	8	4.30	8,375	513
89,000	0.9	13.8	64	4.00	1,391	2,876
112,000	0.9	13.8	72	4.70	1,556	3,021

6.2.2.1 Delivery Time

When generator uprating is combined with turbine uprating, the turbine delivery times and installation are usually sufficient for the equivalent generator work. When generator uprating is undertaken independently, the time required for generator modifications can be roughly estimated from the information in Table 6-3:

Table 6-3
Typical Range of Generator Delivery Times

	5 MVA Unit	100 MVA Unit
Delivery of embedded parts (from receipt of order)	4 months	12 months
Delivery of remaining parts (from receipt of order)	9 months	20 months
Completion of commissioning and installation (from receipt of order)	12 months	30 months

6.2.3 Generator Rewinds

The cost of rewinding generators with new stator windings can be determined from the following "rule of thumb" formulas:

1. Supply Cost (of coils or Roebel bar type windings)
   - Machines up to about 150 MW: $2,500–$4,000 per MW of nameplate rating
   - Machines above 150 MW: $1,500–$2,500 per MW of nameplate rating
2. Labor Costs
   - Coil type: $7–$10 per slot
   - Roebel bar type: $13–$17 per slot

The above costs do not include site preparation that would involve unit isolation, removal of the rotor, erection of scaffolding and work platforms, and re-installation of the rotor. These costs are site specific and difficult to generalize.

Sample supply and installation costs of pre-formed coils, taken from recent contracts, are provided in Table 6-4.

Table 6-4
Generator Rewinds

Type	Capacity kVA	Voltage kV	Stator Height mm	Number of Slots	Number of Turns	Supply Cost US$	Install Cost US$
Pre-formed coils	20,000	7.2	900	540	3.00	370,000	330,000
Pre-formed coils	24,000	7.2	840	378	6.00	670,000	290,000
Pre-formed coils	24,000	7.2	900	540	3.00	500,000	270,000
Pre-formed coils	44,300	13.8	1800	504	5.00	600,000	270,000
Pre-formed coils	44,500	13.8	1020	378	7.00	420,000	290,000
Pre-formed coils	44,500	13.8	1270	405	3.00	390,000	280,000

Supply time of the coils depends on factory loading and the premium the owner is willing to pay for faster delivery times. Four to 16 months is common with 4 months being a “fast-track” project.

The time required to install new windings depends on many factors including the type of winding, the access to cranes, the size and skill level of the installation crew, and the number of shifts being run each day. Another factor is how much preparation work has been done at the factory and how much has been left for site crews.

Installation time can be estimated by using the following formula:

$$\text{Installation time} = \frac{N \times P}{C_s \times C_H \times C_N} \text{ hours}$$

where:

N = Number of slots

P = Person-hours per slot:

- 9–11 hours per slot can be used for coils
- 20–25 hours per slot can be used for Roebel bar type

C_s = Number of people in the installation crew per shift. For small units, the maximum crew size is 4–6 people. For large units, crew size can increase to 8–10 people.

C_H = Number of hours in a crew shift

C_N = Number of shifts per day

Since only a limited number of people can work on the unit at a time, the only way to speed up installation time is to increase the number of shifts.

Two to four weeks should be added to the estimate of installation time to cover unit isolation, dismantling, erection of work platforms, and re-installation of the rotor.

6.2.4 Rewedging Costs

Rewedging costs can vary widely due to the different types of wedge designs and materials. However, as a general rule of thumb, the cost of materials is approximately $0.70 per 1 inch (2.54 cm) of slot length. This includes the wedges and all packing and insulating materials.

The time taken by a skilled tradesperson to replace wedges averages out at approximately 60 inches (152.4 cm) per hour. This includes the time to strip away the old wedges, repack, and install the new wedges. It does not include the preparation costs of taking the machine out of service and isolating, removing the rotor, and building platforms. These are very site specific and must be estimated on a case-by-case basis.

Thus the cost of rewedging can be estimated as follows:

$$\text{Cost} = \$0.70 \times L \times N + \frac{L \times N \times W}{60}$$

where:

L = Length of stator slot (inches)

N = Number of slots

W = Hourly wage of workers in dollars

Delivery of materials can be estimated at two to three weeks. Installation time (not including the machine setup costs described above) can be estimated using the following formula:

$$\text{Installation time} = \frac{L \times N}{60} \text{ hours}$$

6.2.5 Field Winding Re-Insulation

Sample costs from recent field winding re-insulation contracts are provided in Table 6-5. For an initial cost estimate of refurbished poles from the factory, $3,000 to $3,500 per pole can be used.

Table 6-5
Generator Field Winding Re-Insulation

Unit Speed rpm	Number of Poles	Pole Height	Cost 2001 US$	Cost/Pole 2001
100	72	840	190,000	2,639
100	72	900	210,000	2,917
100	72	900	280,000	3,889
100	72	1020	190,000	2,639
100	72	1270	190,000	2,639
120	60	1800	220,000	3,667

The field winding re-insulation is a straight production job, and turnaround times from the factory or shop should be estimated at three to four months. Site work scheduling highly depends on the size and skill level of the crews, the number of crew shifts, access to cranes, and is therefore difficult to estimate. Four to six weeks is typically required for an average size machine.

6.3 Excitation Systems

Sample costs of redundant static thyristor bridge excitation systems ("top of the line" excitation system) taken from recent contracts are provided in Table 6-6. For excitation systems, cost depends on the rated and ceiling voltages and currents. Ceiling voltages are specified as a factor of the nominal voltage (ceiling voltage can vary from 2.3 V_n to 7.8 V_n and ceiling current is usually specified as 1.5 I_n). A high-ceiling voltage or current specification can triple the cost of an excitation system. Furthermore, any other special technical requirements can cause a large escalation in costs.

Table 6-6
Supply Cost Versus Ceiling Current

Type	Rated Current Ir	Ceiling Current Ic	Rated Voltage V	Ceiling Voltage V	Generator Volts kV	Supply Cost 2001 US$
Static thyristor bridge systems	580	850	260	468	7.2	100,000
Static thyristor bridge systems	600	900	250	473	7.2	102,000
Static thyristor bridge systems	705	1060	296	485	7.2	143,000
Static thyristor bridge systems	880	1200	250	457	13.8	156,000
Static thyristor bridge systems	880	1200	250	457	7.2	158,000
Static thyristor bridge systems	1500	2040	250	422	13.8	116,000
Static thyristor bridge systems	1600	2600	250	480	13.8	190,000

Figure 6-1 is a graph of the supply cost versus ceiling current specification for the data provided in Table 6-6.

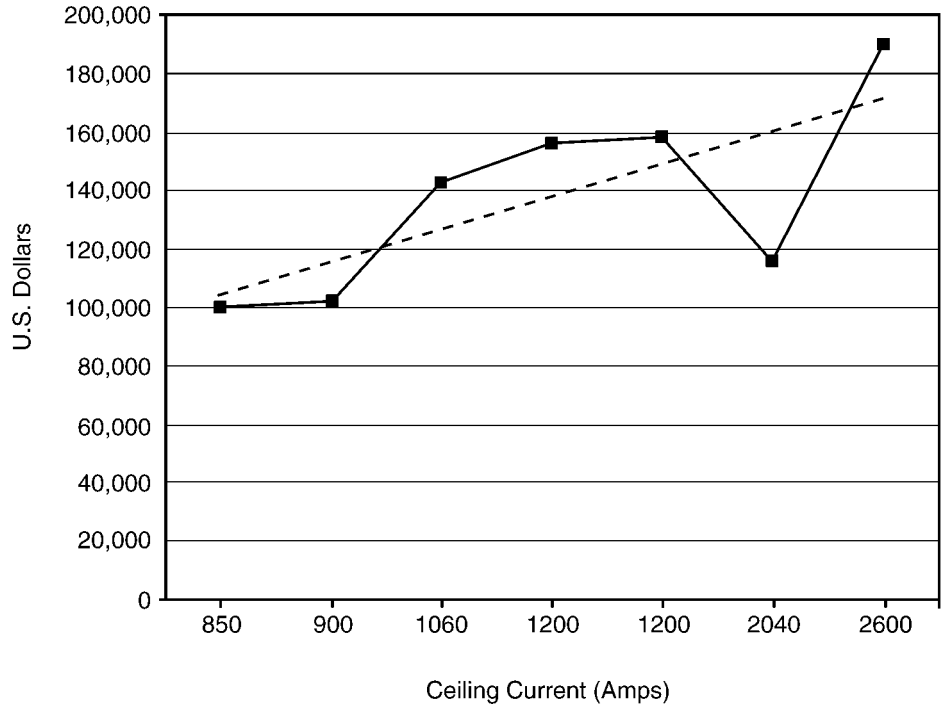

Figure 6-1
Supply Cost Versus Ceiling Current

Delivery times are difficult to estimate for non- “off the shelf” systems. They vary considerably due to factory loading at the time of order. Generally, a minimum of 3 months for any type of excitation system is expected and an absolute maximum delivery time would be approximately 12 months. Engineering time should be added if a rotating exciter is being replaced with a static excitation system.

6.4 Circuit Breakers

The cost of circuit breakers depends on rated voltage and rated continuous current. There is a 4000 A threshold above which the number of suppliers who can supply such high current breakers drops to one.

Figure 6-2 shows the approximate cost of unit breakers.

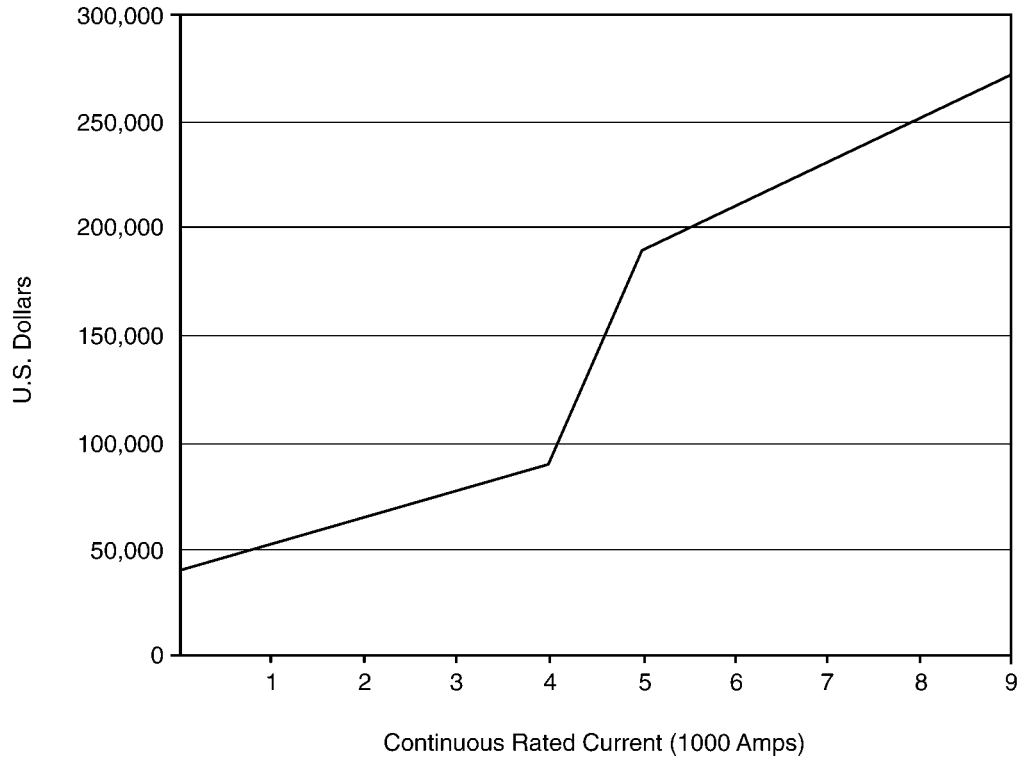

Figure 6-2
Circuit Breaker Costs

Delivery times of unit breakers are difficult to predict for non- "off the shelf" or custom designs. They vary considerably due to factory loading at the time of order. Generally, a minimum of 3 months is expected, with maximum delivery time of not more than approximately 12 months.

6.5 Generator Thrust Bearings

Thrust bearing repair usually involves either rebabbitting of thrust pads or the purchase of new manufactured pads from local shops of the OEM.

The cost of rebabbitting a six-pad set for a 30 to 60 MW machine is approximately $6,000 to $10,000.

The cost of new pads can vary greatly depending on whether they are obtained from local shops or the OEM.

The experience of some utilities is that pads manufactured by local shops from drawings can be one-third the price of pads purchased from the OEM. New pads for a 30–60 MW machine typically cost around $10,000 from local shops. Large babbitting specialty shops in major centers also do very good repair work, but rebabbitting can cost 75–125% more than obtaining them from local smaller shops. The owner should obtain quotes from both local shops and the OEM to obtain the best prices.

6.6 Generator Cooling

Estimating the cost of upgrading the generator cooling system is difficult because of the numerous alternatives available. However, for the purposes of these guidelines, the cost of overhauling the generator cooling system can be estimated to be 25% of the cost of a new system. Similarly, the cost to uprate the system capacity by 30% can be estimated to be 50% of the cost of a new system.

Figure 6-3 shows approximate costs for a new (installed), typical single open-circuit cooling water system for one unit. For double circuit systems (that incorporate a closed-loop system), the costs should be doubled.

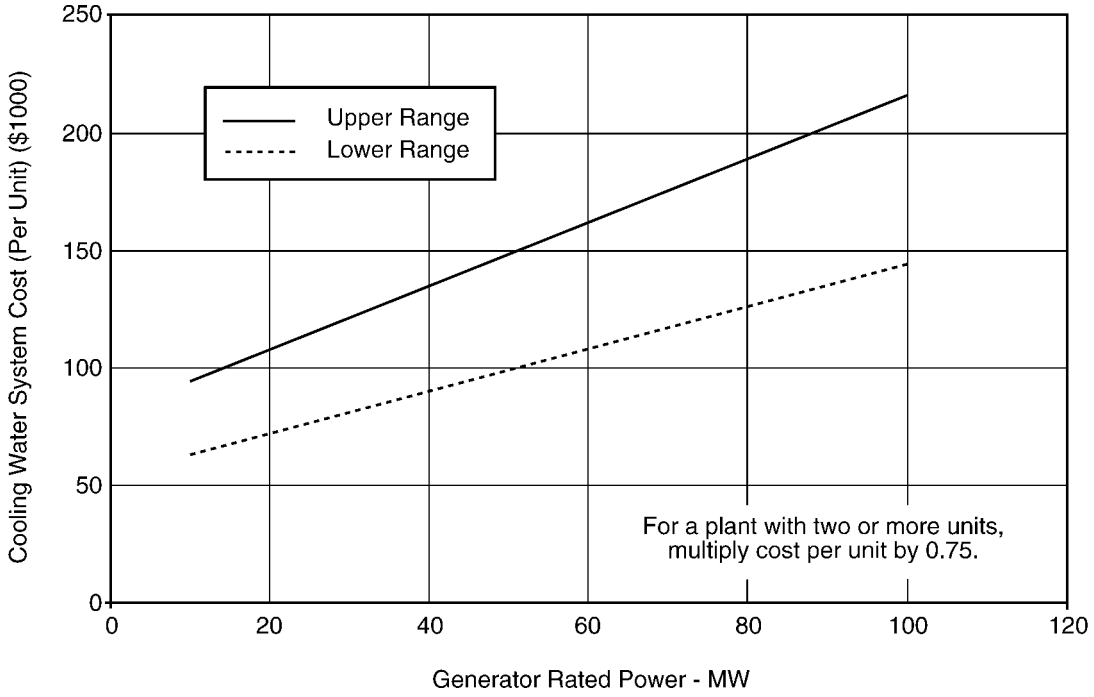

Figure 6-3
Cooling Water System Cost (Single Pass)

6.7 Project Costs

The estimated costs of a project usually include:

- Direct costs
- Contingency
- Escalation
- Indirect costs
- Interest during construction (IDC)
- Other costs

Capital costs are those that result in an asset improvement include all the costs above except for "other costs" which are generally under the heading of O&M.

Each of these areas will be discussed briefly for completeness. The use of the example electronic economic/financial evaluation template provided with Volume 1, Chapter 4.9 will simplify the process for evaluating the impact of the electrical activities on the plant. The template eliminates the need to calculate individual contingencies, escalation and IDC for each identified project, because these are set for all projects entered into the template in the "Assumptions" area of the template. Costs are also used as input in the optimization of electrical improvements.

6.7.1 Capital Costs

Capital costs for a project consist of the direct costs, contingency, escalation, indirect costs, and IDC.

- Direct Costs - Direct costs include the costs of all direct equipment, material, and construction costs associated with disassembly, assembly, and testing.
- Contingency - The contingency to provide for inaccuracies in the direct costs estimates depends on the confidence level of the direct costs. For the estimates for LEM plans, a contingency factor of 20 percent (CF = 0.20) is suggested.
- Escalation - Escalation is the annual increase in costs due to inflation and other factors, such as material and labor costs. The direct costs determined from these guidelines are in 2000 US$ and should be escalated to the midpoint of the construction period, as determined from the Milestone Schedule. The escalation factor can be determined from the following equation:

  $$\text{Escalation Factor (EF)} = (1 + e)^n - 1 \qquad \textbf{Eq. 6-1}$$

where:

e = annual escalation rate in decimal value

n = number of years between the date of direct cost dollar values and the date of midpoint of construction

The value to be used for escalation can be determined from either the Handy-Whitman or USBR indices as described in Section 6.1. A suggested value is 3.0% per year (e = 0.03).

- Indirect Costs - Indirect costs consist of the costs for administration permits, licensing, engineering, construction management, training, and startup. For the runner modernization considered in these guidelines, an indirect cost factor (ICF) of 20% (ICF = 0.20) is suggested.
- IDC - IDC is the interest paid on the money borrowed to finance the implementation of the plan. IDC is calculated from the midpoint of the Milestone Construction Schedule to the date of commercial operation. IDC is only applicable to plan costs treated as capital improvements where the costs are to be included in a rate base. For plans in which costs are

treated as maintenance costs, IDC should not be applied. Similarly, for upgrade projects completed in less than a year, interest during construction is insignificant and may be excluded. The rates to be used can be determined from one of the following equations:

$$\text{IDC Factor (IDCF)} = (1 + r)^n - 1 \text{ (compounded)} \quad \textbf{Eq. 6-2}$$

$$\text{IDC Factor (IDCF)} = r \times n \text{ (simple)} \quad \textbf{Eq. 6-3}$$

where:

r = interest rate in decimal value

n = number of years from the midpoint of construction to the date of operation

Interest rates are typically 3–5% above the escalation rate. A suggested value is 9% (r = 0.09).

6.7.2 Present Value of Total Capital Cost

In present value evaluations, the total capital costs of a plan are not the dollar value used for the evaluation. The value required is the present value of costs incurred due to the commitment of the total capital costs. These costs include taxes, insurance, depreciation, return on investment, finance charges, and other administrative costs. These costs are called "fixed charges" and are typically assessed as a percentage of the total capital costs each year. Therefore, the fixed charges vary each year as the total capital costs vary. To simplify economic evaluations, the fixed charges can be converted to uniform annual payments called levelized annual fixed charges. This uniform annual payment is computed by dividing the sum of the present valued annual fixed charges over the economic life of the project by the sum of the present value factors. The uniform annual payment divided by the total capital cost is the levelized annual fixed charge rate.

The present value of these fixed charges corresponds to the date of commercial operation. The present value of the total capital costs is the fixed charge factor times the total capital costs. The fixed charge factor is calculated as follows:

$$\text{Fixed charge factor (FCF)} = \text{LAFCR} \times \text{SPVF} \quad \textbf{Eq. 6-4}$$

where:

LAFCR = the levelized annual fixed charge rate in decimal value

SPVF = the sum of the present value factors for the economic life of the modernization

SPVF is calculated as follows:

$$SPVF = \frac{(1+i)^n - 1}{i(1+i)^n} \qquad \textbf{Eq. 6-5}$$

where:

i = the present worth discount rate in decimal value

n = the number of years in the economic life

For organizations with ongoing improvements, these values may be readily available. However, when the values cannot be easily calculated, suggested values for FCF are 1.10 for public agencies and 1.30 for investor-owned utilities. The FCF is a number developed to quickly calculate the present value of the total capital cost in lieu of calculating the annual present value of the fixed charges and summing.

The present value fixed charges presented previously are based on the date the upgrade plan is put into commercial operation. These costs must be adjusted to the date of the study by multiplying by the present value adjustment factor. The present value adjustment factor (PVAF) is calculated as follows:

$$PVAF = 1/(1+i)^t \qquad \textbf{Eq. 6-6}$$

where:

i = discount rate (0.09)

t = number of years between the study and commercial operating date of plan

6.7.3 Other Costs

Any other costs should be estimated and added to the total cost. For example, such costs might include the increased O&M costs incurred while a unit is modernized.

The sum of the present value of the following costs—total capital and other costs—gives the total present value of upgrading, which is then compared to the operating benefits of the modernization plan. The present value of these costs should be at the date of the study.

6.7.4 Cost Estimates at the Feasibility and Project Approval Stage

While the cost estimates presented in the preceding subsections are suitable for screening and planning studies, estimates with reduced uncertainty will usually be necessary for project approval, prior to implementation. Volume 1, Chapter 2.3.5 describes various estimating considerations.

Indirect cost and interest during construction may require review to check any revision to the owner's specific financial/economic parameters. The use of the model will reduce or negate this requirement if the appropriate parameters are initially entered into the supporting tables portion of the model.

Cost estimates for supply of electromechanical equipment should be obtained from generator manufacturers or developed from actual prices for previous projects of similar type, capacity, and physical size.

Depending on the confidence in the cost estimate, it may be possible to reduce the contingency to as low as 10% of direct cost. The owner's policy on contingencies, however, will determine the contingency percentage to be included.

6.8 Energy and Capacity Benefits from Modernization

6.8.1 Energy

The expected energy benefit of an electromechanical modernization activity will be refined as the planning process moves from the formulation of an LEM plan through to the feasibility process. An initial estimation of energy benefits from a particular activity can be gained from the methods described in Chapter 5. During the feasibility process in Chapter 7 of Volumes 1 and 3, the initial estimates of energy benefits will be refined through more detailed analysis and discussion with manufacturers.

The benefits of a modernization activity can be compared against the base case for the plant. The base case will usually include all activities necessary to maintain the plant at its present output.

For the existing plant, the average annual generation can be determined from the generation records for at least the past 5–10 years, and preferably for the last 10–20 years. The historical generation may require adjustment if generation was affected by planned outages or non-representative water years. A power study, described in Volume 6, may be required to provide a more accurate picture for the plant.

The model supplied for use with Volume 1, Chapter 4.9 simplifies the input of benefits for each project. The model accepts standardized energy value forecasts in its supporting tables section. Expected generation benefits can also be inserted in the same area. Refer to the user materials supplied on the CD-ROM containing the model.

6.8.2 Value of Energy

Information about the value of energy will be of assistance to users who may not have easy access to pricing information for a first pass evaluation of a proposed project. Similarly, the present value information is not required if the model is used as present value calculations are incorporated in the model.

The value of the generation ($/MWh) depends on whether the generation cannot be stored and is run-of-river or can be stored and scheduled to be used during peak periods as peaking energy. Run-of-river generation should be assessed at new baseload unit costs, while generation from units that have storage and can be used for peaking should be assessed at peaking energy costs. For units that have some storage and can be used partially for peaking, the baseload and peaking generation can be proportioned accordingly. Each user of these guidelines should use values for peak and non-peak power costs and proportioning that reflect the actual situation under consideration. For example, if the hydro generation is offsetting three levels of alternative generation costs—gas turbines (10%), coal-fired units (50%), and non-peak baseload (40%)—then the value of generation (VG) computation will consist of three components rather than two as illustrated in these guidelines. Every attempt should be made to obtain the value of generation ($/MWh) from an internal company source. This helps to compare projects across the generation fleet to the same benchmark. There are some publicly available sources, but extreme caution must be exercised. It may be better to base the value of the project on cost savings gained/lost comparing multiple project alternatives assuming various plant capacity factors. An escalation rate of 5% can be used if the escalation rate is unknown.

The present value of the energy generation from the upgraded plant can be determined by applying the PVAF from Equation 6-6 to the following:

$$\text{Energy generation after upgrade} = VG \times \frac{\left(1 - k^{n}\right)}{\left(1 - k\right)} \times PVAF, \qquad \textbf{Eq. 6-7}$$

where:

$$k = \frac{1 + e}{1 + i}$$

VG = value of annual generation (peak and non-peak) on the date of commercial operation (MWh/yr x $/MWh)

n = evaluation period in years (15)

e = escalation rate (0.05)

i = discount rate (0.09)

PVAF = present value adjustment factor

6.8.3 Capacity

Capacity benefits will be refined in a similar manner to energy benefits. The plant capacity for each upgrading alternative is determined during development of the alternatives.

The value of capacity depends on whether the capacity is considered to be dependable, which is influenced by whether the plant is a baseload run-of-river plant, has storage for peaking, or is a combination of run-of-river and peaking. As with the energy costs, the capacity attributable to each category should be estimated and proportioned. If the value of capacity is unknown, values can be obtained from publications such as "Power Generation Markets Quarterly."

For units installed in years other than 2000, the capital cost escalation rate of 5%, as determined earlier, should be used to escalate the cost to a different year of installation.

The present value of the upgraded plant capacity in study date dollar values can be determined by applying the PVAF from Equation 6-6 to the following:

Present value of capacity

$$\text{for existing plant after upgrade} = VG \times k \times \frac{\left(1 - k^{n}\right)}{\left(1 - k\right)} \times PVAF, \qquad \textbf{Eq. 6-8}$$

where:

$$k = \frac{1 + e}{1 + i},$$

VG = value of capacity on the date of commercial operation

N = evaluation period in years (15)

E = escalation rate (0.0)

i = discount rate (0.09)

PVAF = present value adjustment factor

Evaluation of capacity credits varies by utility. Full credit for any increased capacity may not be allowed if the capacity is not considered dependable, that is, if water is not always available for the plant to operate at maximum capacity. If system criteria are available to determine how much of the increased capacity can be considered dependable, these criteria should be considered in the capacity evaluation. If capacity credit criteria are not available, the full capacity should be credited.

6.9 Other Benefits from Improvement

In addition to the improvement in performance, there may be several other benefits to an LEM program from an electromechanical perspective including:

- Reduced repair costs
- Reduced maintenance costs
- Increased value of the asset
- Increase in availability
- Increase in operating flexibility
- Reduced risk and insurance costs
- More environmentally friendly equipment

Each benefit will require assessment for each individual project proposed. Some benefits will be difficult to define financially and may be better treated using a value based management approach if the owner is inclined to use such a system. The use of risk cost benefits in the evaluation of the project/plant benefits will also be dependent upon the owner's requirements. There is provision for risk costs benefits to be incorporated into the model if desired.

6.10 Input to Life Extension and Modernization Plan

The cost estimates of Chapter 6 are used to assist with the early stage LEM plan development. Further refinement of costs continues as a project moves from the LEM plan to the feasibility stage. Costs and benefits are inputs into the model (financial), described in Volume 1, Chapter 4.9.

7
FEASIBILITY: OPTIMIZATION OF ALTERNATIVES

7.1 Introduction

The owner will either have an experienced and knowledgeable engineering staff or will select a suitable consultant for the feasibility stage analysis of LEM of projects. Consequently, Chapter 7 guidelines are brief.

Chapters 4, 5, and 6 of this volume contribute to the formulation of an LEM plan for electromechanical equipment. The information used to formulate the LEM plan is obtained largely from existing operational and test data, reports and site visits, and inspections.

At the completion of the LEM plan, the most favorable LEM activities will be selected for more detailed study at the feasibility level. This work should be undertaken in parallel with any possible upgrading of the turbine, protection, and control system and unit transformer (Volumes 2, 4, 5, and 7). The projects identified in the selected LEM plan(s) may require more accurate, up-to-date information to:

- Verify the technical feasibility by:
  - Identifying and optimizing alternative activities (see Chapters 7.2, 7.3, and 7.4)
  - Selecting the best activities (see Chapter 7.5)
  - Undertaking a sensitivity analysis (see Chapter 7.6)
- Proceed with the design (see Chapter 8)
- Implement the project (see Chapter 8)

Chapter 7 outlines methods for obtaining more detailed information on equipment condition and modernization opportunities.

The additional required information may come from:

- Additional testing (individual component testing)
- Additional inspections (with equipment out of service) and disassembly
- Engineering assessment
- OEM and vendor participation

The acquisition of testing and inspection information might require a commitment from the owner to operate each unit in a noncommercial manner and usually requires the unit to be taken out of service for a period of time. The results of the detailed inspection and testing are valuable, even if they mean that the proposed modernization is not feasible and no further action is taken. The test results will provide a performance baseline for future assessments of the plant.

Figure 7-1 describes how the subsections of Chapter 7 contribute to the feasibility assessment of the LEM activities identified in Chapters 4 and 5.

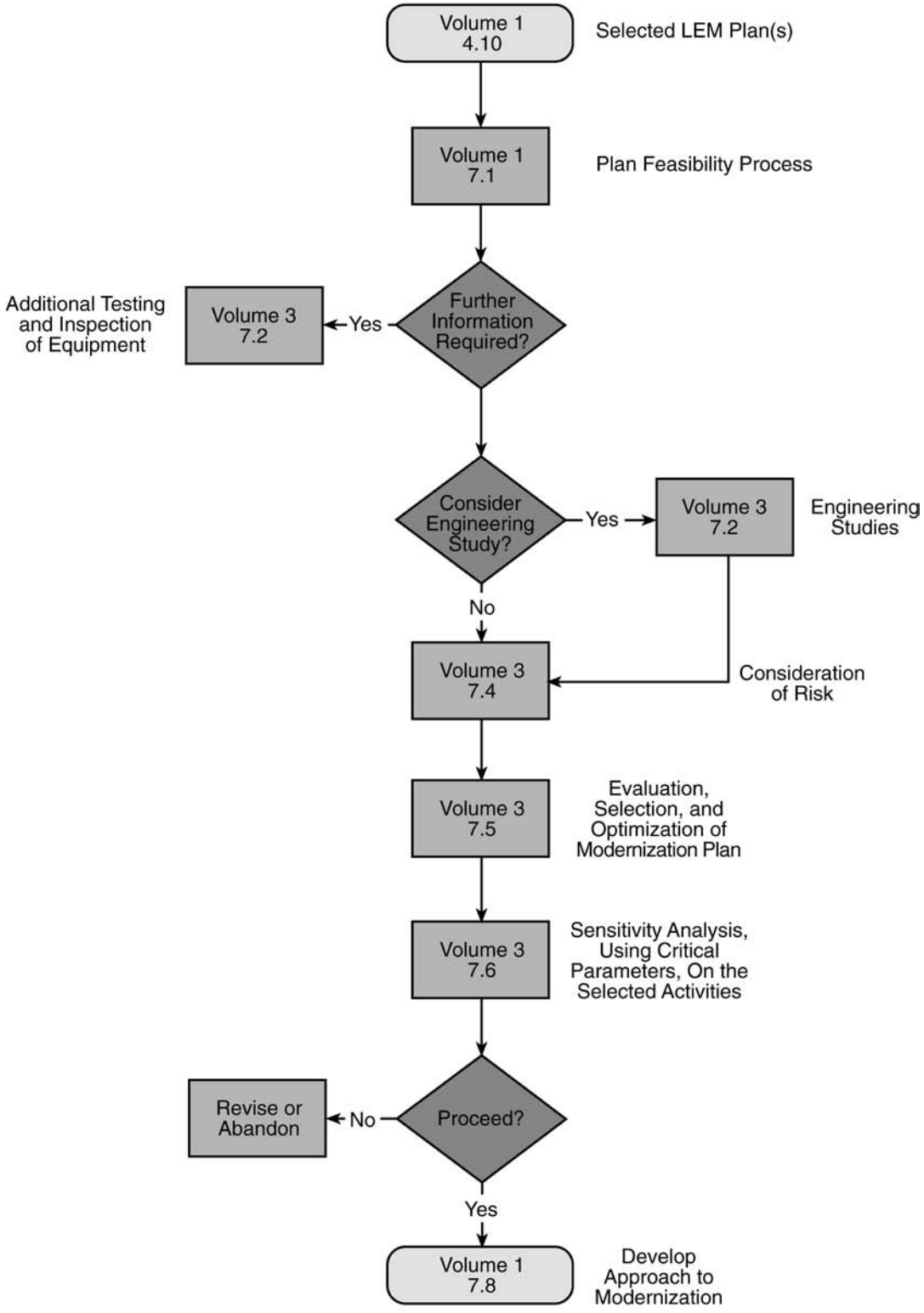

Figure 7-1
Optimization of Alternatives Flowchart

7.2 Additional Testing and Inspection of Electromechanical Equipment

The documentation in Chapters 4 and 5 of this volume will likely be sufficiently complete to narrow the feasibility study to one or two alternative actions.

However, partial disassembly may improve confidence in previous inspections, tests, and expert advice. For example, removal of work that can be reversed, such as windings from selected field pole(s) and front stator bars (or half-coils) might reveal new options. Destructive and irreversible steps should be avoided until a final LEM plan is developed, approved, and scheduled. Some additional tests and inspections to be considered include:

- Dye penetrant tests of structural components, particularly spider, stator frame, and bearing brackets
- Life endurance tests (reduced voltage) of removed stator bars/half-coils with PD analysis and dissections
- Random inspections of bolted and brazed joints
- Removal of thrust bearing pad(s) and measurement of surface flatness and support spring (if used) coefficients
- Removal of selected field windings to inspect collars and pole insulation
- Temporary installation of diagnostic monitoring equipment for use during the operational period before completing the LEM plan
- Core bolt tightness checks

7.3 Engineering Studies

Engineering studies are used to bring the required information together to make rational decisions on the feasibility of specific electromechanical improvement activities. The process covers:

- Assessment of previously gathered information (Volume 3, Chapters 4 and 5)
- Assessment of results of inspection and testing (Volume 3, Chapter 7.2)
- Analysis of effects of proposed modernization on overall plant (Volume 3, Chapter 5.7)
- Buildability analysis (Volume 1, Chapter 7.4)
- Value engineering (Volume 1, Chapter 7.4)
- Improvements in assessment of costs (Volume 3, Chapter 6)
- Improvements in assessment of benefits (Volume 3, Chapter 6)
- Selection of best electromechanical equipment modernization (Volume 3, Chapter 5)

The iterative nature of the LEM planning process is intended to optimize outlays, not to commit large amounts to studies that should not be conducted until preliminary studies indicate that the proposed project has merit.

7.4 Risk Considerations

Risk management is the ability to balance risks with potential gains by making wise decisions. The process outlined in this volume is the first step in reducing the owner's risk.

As part of the feasibility study process, the risks associated with each option should be assessed. Each risk, along with the potential mitigation available, can be identified. Risk areas to be considered from a purely electromechanical perspective are:

Area	Risk
Technical and technological	• Proposed modernization activity is not feasible • New equipment does not meet performance levels • Technology changes make modernization obsolete • Inadequate assessment of condition • Incorrect designs and inadequate quality assurance • Once work is initiated, more needed work is identified
Construction	• Inadequate procurement process • Delayed schedule, longer outages • Consequential damage • Contractor unfamiliar with specific work • Poor estimates of cost leading to overruns • Worker safety
Environmental	• Disposal of used materials • Pollution and spills
Operating	• New operation does not achieve expected gains

The user should examine all of these areas with particular regard to the electromechanical activities resulting from work associated with this volume.

The risks identified by this process must be examined for their acceptability. If some risks are apparently unacceptable as they stand, then the mitigation available to reduce the risks to acceptable levels must be identified. If the cost of mitigation is uneconomical, then the risks are confirmed as unacceptable and the project or activity is not feasible. If the mitigation can reduce risks to an acceptable level at an economical price, then the costs of the mitigation will be included in the financial evaluation conducted during the feasibility study.

Volume 1, Chapters 2.3.2, 4.6, and 7.5 address risk identification and management and should be used as a reference. Additional detailed evaluation and management of risk issues is beyond the scope of these guidelines.

7.5 Evaluation, Selection, and Optimization of Modernization Plan

Modernization activities (opportunities) are identified, assessed, and screened as part of Chapter 5 of this volume and Volume 1, Chapter 4. This provides an LEM plan for electromechanical equipment in the context of the overall plant. The next stage in the process is to evaluate the proposed activities in more detail and to optimize the activities. This requires additional testing and inspection of equipment (Chapter 7.2), engineering studies (Chapter 7.3), and the identification and evaluation of the risks associated with each proposed activity or project (Chapter 7.4).

With the results of the work associated with Chapters 7.2, 7.3, and 7.4, all options explored during feasibility can now be evaluated. This enables a final modernization plan to be selected and optimized before undergoing a final sensitivity analysis (Chapter 7.6).

In some cases, the additional data, gathered during the feasibility process, sheds new light on the whole process eliminating some of the options originally scheduled in the LEM plan. The option that moved forward from the formulation of the initial LEM plan might have to be reconsidered. For example, if an item of equipment is more seriously deteriorated than initially thought, or its performance is worse than originally measured, the cost of replacement or repair may be higher than expected, or alternatively, the case for modernization may become more attractive.

Cost and benefit information should also be reviewed at this point to feasibility level (refer to Volume 1, Chapter 7.6 and Volume 3, Chapter 6) to enable selection of the appropriate LEM plan.

7.6 Sensitivity Analysis Using Critical Parameters of Costs and Benefits

An integral part of the project analysis is conducting a sensitivity analysis on the selected modernization plan using parameters that are critical to the selected modernization project's success. These parameters can be separated into two categories: costs and benefits.

Some of the parameters discussed are applicable in some cases but not in others. For example, delays in construction that extend a unit outage may have consequential costs in some cases but, in other cases, where the plant may be water constrained, an extended outage will not incur any additional lost production costs.

The project under consideration may be a distinct project or part of a program of projects to modernize a plant. The sensitivity analysis for the project may form part of a larger sensitivity analysis. Usually, however, the sensitivity analysis will be for the modernization process as a whole.

The sensitivity analysis for each identified project is conducted within the electronic template used in Volume 1, Chapter 4.9. The user guide supplied with the template describes how to conduct the sensitivity analysis within the template. Some of the parameters described are combined before insertion into the template.

The range used in the analysis for each parameter depends on the individual circumstances of each owner and of each plant. These guidelines do not attempt to specify any ranges to be used.

The parameters examined could be combined in a multitude of scenarios. These guidelines do not attempt to distinguish between the possible scenarios, because each individual project and plant examined has its own particular circumstances at any given time.

7.6.1 Costs

Cost parameters to be assessed for sensitivity analysis include:

- Engineering costs
- Licensing costs
- Construction costs

7.6.1.1 Engineering Costs

Engineering costs include those associated with the detailed engineering design following the decision to proceed.

7.6.1.2 Licensing Costs

Licensing costs include all those associated with the relicensing process applicable to the project under consideration. This can be a particular area of concern due to the open-ended nature of the process. Volume 1, Chapter 6 contains details of the relicensing process.

7.6.1.3 Construction Costs

Construction costs include all costs associated with the construction process. These can include costs associated with:

- Claims for extras by the contractor(s)
- Consequential costs from the contractor's claims, for example, other contractor claims, legal costs, and administration costs
- Delays to the completion of the project that could incur costs to the owner, for example, additional administration costs and cost of additional lost production
- Escalation (if the project is over an extended period of time)
- Interest rate movements
- Exchange rate movements

7.6.2 Benefits

Benefit parameters to be assessed for a sensitivity analysis include:

- Capacity/efficiency
- Availability
- Value of energy
- Fuel cost

7.6.2.1 Capacity/Efficiency

The expected capacity improvement from the project is well-defined at this stage. A sensitivity analysis of capacity focuses on the economic effects of a shortfall in capacity from the projected valves. In the case of replacement stator components, there might be higher losses, and these can be assessed using the same analysis method as used for capacity.

7.6.2.2 Availability

A sensitivity analysis of availability depends on the individual plant under consideration. Availability for some plants is not an issue due to system requirements, that is, its use is flexible or it has water constraints. In today's changing market, however, availability is extremely important. Each owner must quantify how it wishes to treat availability financially as a benefit. The value to an owner of a flexible plant that is consistently available for service will depend on the owner's circumstances, products, and market arrangements. Obviously, however, the greater the availability of the unit the greater the opportunity to take advantage of the market.

7.6.2.3 Value of Energy

The expected value of energy in the future has been predicted by the owner in the electronic template used in Volume 1, Chapter 4.9, but a sensitivity analysis of the prediction might be required. It is difficult to specify a percentage range to assess but, in an open market, this could be high on a short-term basis. Each owner will have its own particular situation.

7.6.2.4 Fuel Cost

Fuel, which in the case of hydro plants is water, normally has costs. These are frequently related to water usage, storage, or capacity costs. The sensitivity analysis considers possible changes (increases) in water usage fees and the shared users of the resource.

8
IMPLEMENTATION OF MODERNIZATION PLAN

8.1 Introduction

Previous sections of this volume have provided information for the user to identify, evaluate, and select an appropriate LEM plan for electromechanical equipment and confirm the feasibility of selected activities. Chapter 8 assists the user in formulating a general plan for implementing the LEM plan. As in Chapter 7, it is assumed that the owner has engineering staff familiar with project management or has retained a consultant to oversee implementation of the final approved LEM plan.

Figure 8-1 outlines the steps involved in preparing proposed LEM activities for implementation.

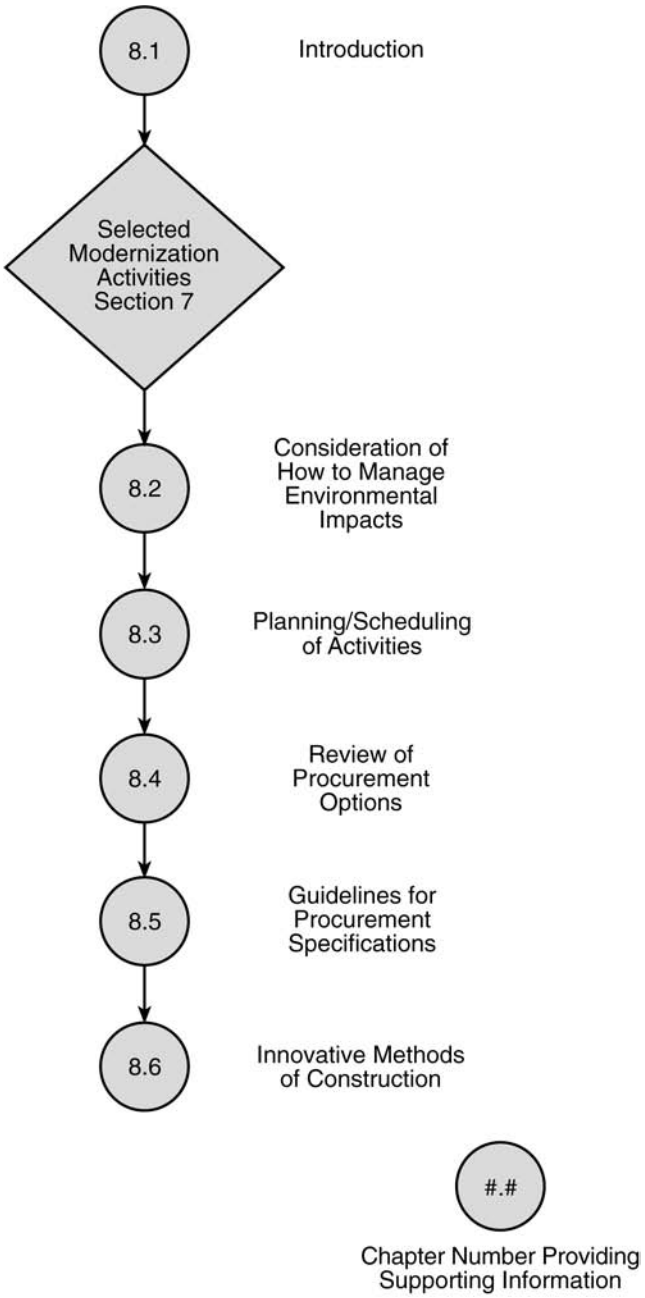

Figure 8-1
Implementation Process

8.2 Environmental Management Considerations

Environmental issues described in Chapter 4 are centered on the possible environmental impacts of LEM projects related to electromechanical equipment. At the implementation stage of the process, the focus turns towards licensing approvals, the schedule to achieve them, and management of environmental matters on site during construction. In addition, the measurement of environmental improvements from the project is a necessary follow-up task. This subject is described extensively in Volume 1, Chapter 6.

8.2.1 Licensing, Approvals, and Schedules

Accurate estimates of improvement in environmental performance are a requirement in the relicensing process. The relicensing process may also require the owner to demonstrate that all available environmental upgrades have been considered and to explain why some upgrade options are not being implemented. This process can be time-consuming, and allowance must be made in the implementation schedule to accommodate this.

8.2.2 Environmental Management Plans

To ensure sound environmental management and to demonstrate due diligence to regulatory authorities and the public, an environmental management plan (EMP) is required for most projects, from painting projects to equipment replacements and operational changes.

The purpose of an EMP is to ensure that the potential environmental impacts of a proposed activity (that does not require a legislated environmental impact assessment) are evaluated, and eliminated, mitigated, or compensated for appropriately, and that these considerations are communicated appropriately in a responsible manner. EMPs also ensure that all required permits, authorizations, and approvals are obtained and documented for due diligence purposes.

Like other environmental assessment tools, EMPs consider a proposed activity in the context of the existing environment to identify potential impacts and mitigation measures, provide an appropriate level of environmental protection, and ensure compliance with appropriate legislation and guidelines.

The content of an EMP depends on the scope of the proposed undertaking. Depending on the complexity of a proposed activity, and the environmental sensitivity, an EMP can be:

- Instructions presented in a pre-job meeting
- A memo or letter
- Clauses in tenders and contracts
- A stand-alone document
- All of the above

An EMP is also a valuable communication tool for the transmission of information in-house and to other stakeholders.

A reference collection of all existing EMPs, permit and authorization information, and other useful material should be collated for easy reference on future projects.

An EMP will usually include the following chapters:

1.0 Introduction

2.0 Project/Activity Description

3.0 Environmental Setting/Valued Ecosystem Components

4.0 Regulatory Requirements

5.0 Potential Environmental Impacts

6.0 Mitigation/Compensation

7.0 Literature Cited

Appendices:

Appendix A Project-Specific Environmental Protection Plan

Appendix B Environment Compliance Monitoring

Appendix C Regulatory Permits and Authorizations

Appendix D Emergency Contact List

Appendix E Material Safety Data Sheets Forms

Appendix F Test Results (for example, analyses of paint)

Appendix G Spill Prevention and Response Measures

Appendix H Environmental Incident Reporting Procedures

Appendix I Suppliers (for example, sorbents)

Appendix J Monitoring Forms

An important part of an EMP is the monitoring requirements for the project. Environmental monitoring requirements should be well laid out and included as clauses in any external contracts for the work.

8.2.3 Construction Phase

Environmental management during the construction phase involves the consideration of the following aspects:

- Interference with the existing environmental management systems (such as drainage systems) in the plant
- Losses to the environment due to mishaps during construction

8.2.3.1 Existing Environmental Systems

When part of a plant is out of operation due to a construction project, the security of the environmental systems in the in-service portion of the plant may be reduced. For example, work on the station drainage system may limit the plant's capability to contain an oil spill occurring in the "in-service" portion of the plant. Close coordination is required during the construction phase to avoid this type of situation. Daily coordination meetings between those involved in the construction project and those involved in plant operations can minimize the risks.

8.2.3.2 Losses to the Environment

The most common environmental risk with construction work is that of direct loss of construction materials and effluent to the environment (for example, oil spill from a governor pressure unit or lube oil system during modifications). The mitigation of these risks lies with the contractor and the construction management team. The responsibilities and penalties associated with working to the required environmental regulations must be clearly defined for all parties at the start of the project. Daily coordination meetings, which include a discussion on activities that are potentially harmful to the environment, can be used as a risk mitigating activity.

Asbestos is one material that must be carefully controlled during work on generators. Armor tape for stator windings and between field turns should be considered.

8.3 Project Definition and Implementation Planning

After the LEM process has moved through its investigation and decision-making phases, and the decision is made to proceed with a particular project, implementation begins.

Implementation consists of defining the project to be commenced and conducting and completing the defined project. Activities include:

- Project management
- Engineering
- Procurement
- Construction
- Construction management

- Testing and commissioning
- Documentation

Volume 1, Chapter 8 describes the project definition and implementation portion of the process in detail. Each user will normally have procedures in place for these activities. Accordingly, the information presented is general in nature and intended to prompt some consideration of alternatives that may not currently be utilized by the user.

8.4 Procurement Options

Procurement options are covered extensively in Volume 1 of these guidelines. The options available to the user usually depend on the procurement philosophy of the owner. Each new project, however, provides an opportunity for the owner to revisit the options available to complete the project.

8.4.1 Traditional Approach

There are three traditional types of contracts available for the completion of hydromechanical works as shown in Figure 8-2. They are divided on the basis of risk allocation.

Cost Reimbursement Contract (Cost Plus)

In this type of contract the owner pays the contractor for the actual cost of the work plus an additional amount representing the agreed profit.

The owner assumes most of the risk in this type of contract. Moreover, the owner usually must survey the quality and quantity of work very closely to ensure that the work is sufficient, of acceptable quality, and performed expeditiously.

This type of contract is seldom used now.

Fixed Price Contract

In this type of contract the contractor agrees to do the required work for a fixed price.

The contractor assumes most of the risk in this type of contract.

This type of contract is popular for electrical and mechanical works where the quantities of work can be estimated accurately. It is also popular where the owner prefers to avoid the uncertainty of the contract cost.

Note, however, that despite the fixed price, there are a number of situations where the contractor may be entitled to extra payments. As with the re-measurement contract the fixed price contract may include provisional sums.

Turnkey Contract

In this type of contract the contractor agrees to design, procure, manage, and implement the work for a fixed price. The contractor assumes most of this risk.

The contractor agrees to undertake the work and deliver the completed project to meet performance specifications. These are set by the owner as performance criteria to be met. The means by which the contractor undertakes the work is generally at their discretion, with payment based on satisfying the performance criteria. On the owner's side, engineering and management costs are sharply reduced. A prime consideration in the setting of performance criteria relates to long-term maintainability, quality, and durability. Contractors can use innovative construction methods to reduce their costs.

Figure 8-2
Types of Contracts

The types of contracts are general philosophies of approaching contracted work. The opportunity to provide some incentive for the contractor to provide performance above that specified as a minimum is available in the form of incentives. Incentives can take the form of:

- Bonus payments for performance improvement beyond the minimum specified. These can be made on a sliding scale.
- Bonus payments for early completion of the work.
- Use of an "open book" methodology with an upper limit on cost of the project and a sharing of the cost saving by an agreed formula.
- Bonus payments formulated in a manner such that there is no possibility of the payment costing more than it is worth.

8.4.2 Partnering

Partnering arrangements between owners and contractors are becoming a common method for the procurement and installation of equipment or for the design and management of projects. Partnering involves the owner and contractor working together in a more open and cooperative atmosphere than that which traditionally exists when conventional "arm's length" contracting is used. The process seeks to solve problems rather than protect against litigation and is helpful in managing situations where hidden risks might exist.

8.4.3 Leasing

An alternative procurement approach for LEM projects involves leasing equipment. The lease arrangement is much the same as for any commercial equipment lease except that ownership of the equipment reverts to the owner at the end of the lease period.

8.4.4 Performance Contracting

In performance contracting, the financing and implementation of improvements to the plant is carried out by a third party. The measured benefits of the improvement are paid to the third party initially to recoup its investment. To enable the transfer of the benefit of the installed improvement, the owner of the plant can have an equity interest in the third party that increases over time and gradually phases out the interest of the proponent that financed and installed the improvement. Depending on the type of improvement, the contract period can be from 5 to 20 years, as depicted in Figure 8-3. This new approach has been used by Acres Productive Technologies since 1998.

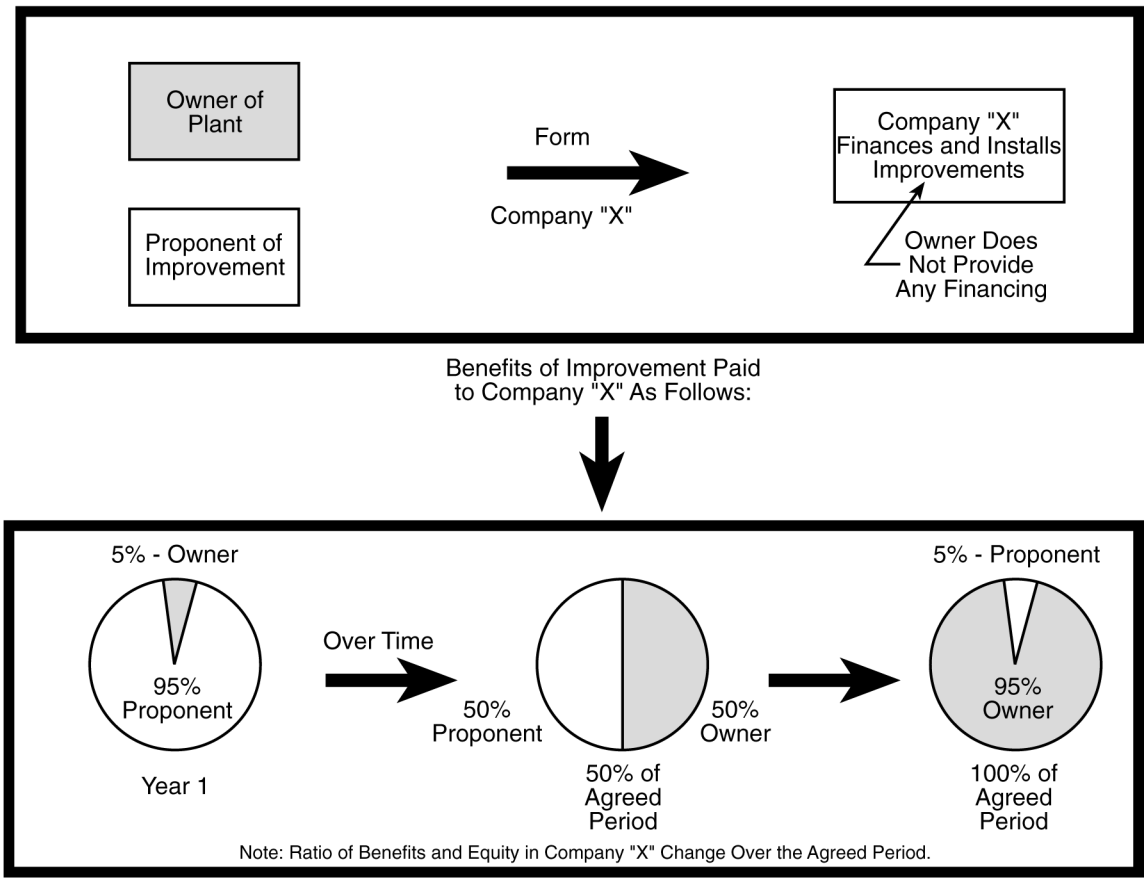

Figure 8-3
Example of Performance Contracting of Improvements

The advantage of this system to the plant owner is that the owner is not required to finance the improvement. The contractor assumes the risk of the project in that he puts up the capital and guarantees the performance as specified in the project contract agreements. The contractor attempts to recover the capital from savings realized by the plant owner. Even if the benefit is only 50% of that expected, the owner has still achieved an improvement at no cost which it will eventually own. The contractor, however, will suffer a loss due to the improvement not being as successful as expected.

There are advantages to forming a third party company to conduct the improvement and allocating a portion of the company equity to the owner. The measurement of the benefit obtained can be clearly defined and a distinct payment for the benefit can be made. Giving the owner an initial small equity position also focuses the owner on accurately measuring the benefit. Also, at the end of the agreement, there can be a clear handover and exit of the improvement proponent.

8.5 Technical Specifications and Legal Documents

Specifications, along with the contracts they are associated with, are the means of sharing risk between the owner and the contractor. Therefore, it is important to ensure that the specification is

designed to correctly define risk and to minimize the risk payment that the contractor can seek from the owner. The more unknowns built into the specification, the more risk cost the contractor may build into the price or attempt to recover through change orders.

This section is designed to provide assistance, at an overview level, to the user when preparing specifications. More detailed sample procurement guides are included in Appendix B. Most owners will have a procurement policy with standard documentation in place. The information given here and in Appendix B does not seek to replace the owner's standard documentation; rather, it is provided to augment it and to allow the owner to research alternative documentation.

These LEM guidelines are not maintenance guidelines. In any major works, however, it is only prudent to incorporate as much work as possible with any modernization work such as a winding replacement. Therefore, reference will be made to other generator refurbishment work in this section.

8.5.1 General

This section describes general guidelines to assist the owner in contracting for generator refurbishment work. It is not always possible to adequately describe the generator condition to allow contractors to prepare fixed price bids for generator overhauls without the contractor incorporating a large risk premium. Prior to bidding, contractors may request to inspect the generator, but these inspections will only reveal superficial defects and give a rough indication of the duration and cost of the refurbishment.

Therefore, the repair of defects found during the refurbishment will usually be billed according to actual expenditures or on a unit price basis.

8.5.2 Request for Qualifications and Proposals

Details of publications that list generator manufacturers and those that also have generator overhaul experience are provided in Appendix C. Owners may choose to add local machine shops that also have overhaul experience. The recommended first step is to select the potential bidders and prepare a Request for Qualifications and Proposals that is sent to each of the selected bidders, unless such a prequalification already exists.

The Request for Qualifications and Proposals should include the following information:

- Generator nameplate data.
- Scope of the work planned.
- Drawings of all generator components subject to refurbishment. The drawings should show the actual generator design including any modifications that have been made to the generator, the dates of the modifications, and the manufacturer. A legal release from the OEM may be required before using the drawings.
- Report of most recent refurbishment work.
- Report of most recent maintenance work.

- List of all known deficiencies.
- Date of pre-bid inspection.
- Overhaul schedule.
- Support services provided by the owner.
- Bid date.

Inspection

A site inspection should be conducted prior to the submission of bids to allow contractors to identify general site conditions including access (or lack thereof). The site inspection should include generator inspection.

During the site inspection the owner should provide a knowledgeable contact person on site to answer questions and clarify the scope of the refurbishment work. It is important that there is only a single source of information from the owner to ensure that all parties receive the same advice so that the bids received are all based on the same information. Formal questions and answers should be issued to all potential bidders.

Bid

The bid should be divided into two parts:

1. Standard overhaul lump sum cost.

2. Unit quantity cost (including salaries and expenses) for unexpected repair and improvement work. In some cases this could be arranged as fixed unit price for particular works if they arise, for example, the owner may list some optional work such as treating stator core bore and slots with penetrating epoxy. Also, the costs could be fixed hourly rates for labor with an invoice plus a fixed percentage handling fee for materials.

The standard scope of refurbishment work includes:

- Disassembly and cleaning of generator components
- Inspection and identification of extra scope work
- Standard repairs
- Standard replacements
- Painting of components
- Supply of additional materials
- Reassembly
- Commissioning tests

Bid Evaluation and Bid Negotiations

The bids received will be evaluated by the owner's personnel or an outside engineer. All competitive bids will be adjusted to the same technical level by negotiations to enable meaningful price comparison. The contract for the refurbishment work is usually signed with the lowest bidder (this does not only include price), unless unusual circumstances require the selection of another bidder.

Contract

The contract consists of the bid proposal and any agreements made during the contract negotiations.

Extra Scope Work

The inspection of equipment performed after disassembling the generator components might reveal unexpected repair work, potential for improvements, and the need for spare parts. Generally, this additional work is authorized by the owner following negotiations and agreement of the additional scope and costs for this work.

8.6 Innovative Methods of Construction

Innovative methods of construction usually develop from an unusual problem that must be solved in the planning stages of a project. Hydropower magazines and journals often present case studies of interesting construction projects that are good sources for keeping abreast of new construction techniques that reduce costs and time. The following are some examples taken directly from published case studies that highlight some interesting approaches to construction.

8.6.1 Use of In-House Crews for Rehabilitation and Upgrade Projects

Sometimes, due to high contractor charges and lump-sum bids combined with the cost of contract specification preparation, administration, and inspection, the use of company personnel to form construction crews can be cost effective. The best qualified and experienced personnel available are removed from their normal positions and may be temporarily replaced by less experienced personnel or contractors. This is an excellent opportunity to develop in-house skills for overhaul work. For the first few projects, the use of an external "Special Construction Crew" to provide specialty expertise and assistance is a good way to reduce risk due to inexperience. Videotapes of the first overhaul can be useful training tools on successive unit overhauls.

8.6.2 Overhaul/Rewind of the Generator at the Same Time as the Turbine Overhaul

Although scheduling the turbine and generator as a combined overhaul can often be economical, sometimes this is not true. Two separate crews competing for floor space, store parts, and crane use can extend the outage time. It might be economical in some cases for turbine and generator overhauls to be scheduled in succession or with only a partial overlap in timing.

8.6.3 Uprating of Cranes

A common large expense associated with runner replacement is the requirement to upgrade the powerhouse cranes. If the rotor was constructed in situ, the crane might not have the rated capacity to lift the complete rotor. A cost-saving measure might be to limit the uprating of crane capacity to the portion of the crane required for removal/installation of the heaviest component (usually the rotor). Limiting crane travel at a certain load might reduce uprating requirements on both the crane rails and bridge and the supporting powerhouse structure.

8.6.4 Jacking the Stator Frame

Instead of removing the rotor, it may be practical to jack the stator frame, core, and winding to provide both stator and rotor access. This is particularly applicable for umbrella designs and overhauls where space is a factor.

8.6.5 Partial Core Replacement

Where a fault has damaged only a limited zone of the core near the bore ends, it is possible to unstack (from the top and bottom) a trapezoidal section or restack with new punchings.

8.6.6 Purchase a Spare Frame/Core/Winding

Combinations of the stator assembly as spares should be considered to reduce the overhaul outage time and lost generation opportunity.

8.6.7 Purchase Replacement Rotor Poles and/or Field Windings

If field windings indicate deteriorated turn insulation, it is often more economical to purchase new windings before the overhaul. The refurbishment of field windings is an onerous task with possible asbestos contamination and special handling requirements.

8.6.8 Modification to Stator Frame

If evidence of unequal expansion or air gap variation exists, there may be reason to release the frame from the concrete anchors and provide radial expansion of the core and frame, thus reducing stresses.

8.6.9 Rewedging of Stator Slots

New materials and designs should be considered and evaluated both technically and economically.

8.6.10 Thrust and Guide Bearing Replacement

New materials with lower friction characteristics may be cost effective (see Chapter 5).

8.6.11 Stator Winding - Reversal

In selected cases, particularly where internal partial discharge is found, the electrical stress can be reduced by "reversing" the winding, that is, line ends become neutral and vice versa.

8.6.12 Neutral Impedance

Some generators might still be rigidly grounded at the neutral connections, in which case ground faults may cause core damage or even fire. Insertion of a transformer and resistance elements and changes to stator winding protection will reduce phase-to-ground fault currents to negligible values.

8.6.13 Innovative Construction Methods During Modernization

Innovative construction techniques have been designed to minimize downtime and revenue loss. At the USBR's Grand Coulee Plant, the replacement stator was constructed outside the unit to be modernized, as opposed to the traditional method of building the stator in situ, and placed into position as a complete unit. This helped to reduce the outage from one year to 70 days with a significant reduction in revenue loss.

Modernization projects for generators have also benefited from process improvements (such as induction brazing) which have produced high quality results, lower costs, and reduced production times.

9
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National Fire Protection Association 20, "Standard for the Installation of Centrifugal Fire Pumps."

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A
LITERATURE REVIEW

Volume 3 Annotated Bibliography of Literature on Electromechanical Equipment

V 3.1

TITLE	**Achieving a 50-year stator winding life**		
AUTHOR	Lyles, John	**COUNTRY**	Canada
PUBLICATION	*Hydro Review*. Vol. 1, No. 6. p. 52–58.		
DATE	December 1994		
KEY FOCUS	Life extension Stator windings		
SUMMARY	This peer reviewed technical paper discusses the use of well-balanced, modern thermostat stator windings which, with the use of complementary on-line monitoring procedures, have the potential of a 50-year life span and can save operators millions of dollars. Comparative costs of maintenance are presented and a reference list is included. Author affiliated with G.E. Armstrong Enterprises, Pickering, ONT.		

V 3.2

TITLE	**Achieving maximum performance from hydro generator ventilation systems**
AUTHOR	Borgna, H. and Garcia, A. **COUNTRY** Argentina
PUBLICATION	*International Journal on Hydropower & Dams*. Vol. 4, No. 3. p. 84–87.
DATE	1997
KEY FOCUS	Generator cooling systems Windage loss
SUMMARY	To reduce windage losses and achieve a uniform distribution of air flow through a generator, it is important to choose the best possible cooling system. This article discusses different types of cooling systems and the relationship of each to winding losses.

V 3.3

TITLE	**Air gap measurements tell generator condition**
AUTHOR	Metcalf, Gerry **COUNTRY** USA
PUBLICATION	*Hydro Review*. Vol. XVI, No. 2. p. 73.
DATE	April 1997
KEY FOCUS	Generator testing Air gap measurement
SUMMARY	Information about the air gap between the rotor and the stator is used to determine the machine's structural condition. Author affiliated with USBR at the Grand Coulee plant, Washington.

V 3.4

TITLE	**Application of both on-line and off-line partial discharge testing on hydrogenerators**
AUTHOR	Green, V., Zhu, H., and Huynh, D. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers.* August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.5

TITLE	**Application of expert systems to interpreting partial discharge measurements**
AUTHOR	Stone, G. C. **COUNTRY** Canada
PUBLICATION	*CEA International Conference on Generator and Motor Partial Discharge Testing*. April 1994.
DATE	1994
KEY FOCUS	Expert Systems Partial discharge analysis Software
SUMMARY	Partial Discharge (PD) testing has become an important tool for assessing the condition of stator winding insulation for high voltage motors and generators. The use of the Machine Insulation Condition Assessment Advisor software in the analysis and interpretation is presented along with the benefits in using PD testing to aid in the predictive maintenance of stator windings. Author affiliated with Iris Power Engineering, Ontario.

V 3.6

TITLE	**Applying new technology in the upgrading or uprating of generators**
AUTHOR	Blecken, W-D. **COUNTRY** Germany
PUBLICATION	*International Journal on Hydropower & Dams*, Vol. 4, No. 6. p. 26–32.
DATE	1997
KEY FOCUS	Generator uprating New technology
SUMMARY	Although hydrogenerators can run reliably for more than 50 years, carefully planned and executed rehabilitation after 20 or 30 years can be more economical even for generators with an excellent record. New materials and design methods, applied to still reliable machines, can increase efficiency and output by 20–30%. The author, associated with Siemens AG, recommends upgrading generators and electrical equipment during turbine outages. New technologies discussed include a stator winding insulation system which requires less ground wall insulation and improves heat transfer from the winding to the core; state-of-the-art field coil insulation; static exciter equipment; fibreglass winding shrouds; poly-tetrafluoroethylene (PTFE) bearing pads and displacement fillets to improve rotor surface quality. An upgrading study is described in detail, and case studies briefly illustrate the advantages of this sort of refurbishment.

V 3.7

TITLE	**Bearing comparison**
AUTHOR	Hindley, Martin **COUNTRY** Canada/USA
PUBLICATION	*International Water Power & Dam Construction*. Vol. 49, No. 10. p. 42–44.
DATE	October 1997
KEY FOCUS	Bearings Greaseless bearings
SUMMARY	A study conducted by BC Hydro subsidiary Powetech Labs, with support from the U.S. Army Corps of Engineers, has provided strong evidence that greaseless bearings, provided they are developed for specific hydropower applications have advantages over more traditional greased-bronze or oil-bronze lubrication systems. Ten different self-lubricating bearing products were tested over thousands of hours. A rating system developed from the testing results offers customers a way of assessing the right product for their hydro equipment. Tables of data and rating charts included.

V 3.8

TITLE	**The case for refurbishing and uprating hydrogenerators**
AUTHOR	Ridley, G.K. **COUNTRY** USA
PUBLICATION	*URHP October 19-21, 1997*, Strasbourg, France. International Water Power & Dam Construction, Surrey, U.K., p. 133–146.
DATE	1987
KEY FOCUS	Generator uprating Generators refurbishment
SUMMARY	A broad survey of the numerous factors which encourage hydroelectric power authorities to both maintain and enhance their generation equipment by periodic major refurbishment. Modern diagnostic procedures are indicated whereby the life of hydrogenerators may be scientifically assessed.

V 3.9

TITLE	**Case studies in partial discharge trend analysis**
AUTHOR	Peterich, T. E. and Ghali, M. W. **COUNTRY** Canada/USA
PUBLICATION	*International Journal on Hydropower and Dams*. Vol. 1, No. 1. p. 40–43.
DATE	January 1994
KEY FOCUS	Condition monitoring Partial discharge analysis Stator windings
SUMMARY	The implementation and use of Partial Discharge Analysis (PDA) has been well used and documented by Ontario Hydro. It allows non-specialists to determine anomalies within a given generator winding. Several case studies illustrating the use of PDA in stator winding condition assessments are given. Extensively illustrated with graphs.

V 3.10

TITLE	**Changing the frequency of an existing generator**
AUTHOR	Weiman, L. and Andersen, D. **COUNTRY** USA
PUBLICATION	*Hydro Review*, Vol. XVIII, No. 7. p. 54–56.
DATE	December 1999
KEY FOCUS	Generator rewinding Rotors
SUMMARY	This paper descries electrical and mechanical analyses prior to a generator rewind at the 125 W Keokuk Power Plant in Iowa. Because Keokuk is a low head, run-of-river plant changes to the speed of the machines had to be kept to a minimum. The most practical approach was to maintain the speed close to the original, and change the number of poles on the rotor, the coil pitch and the connections on the stator. Issues related to the rotor are discussed in detail.

V 3.9.11

TITLE	**Combined uprating and refurbishment of the Ybbs-Persenberg scheme**
AUTHOR	Wedam, G., Lenz, M., and Hartner, H. COUNTRY Austria
PUBLICATION	*International Water Power and Dam Construction*. Vol. 43, No. 10. p. 29–31.
DATE	October 1991
KEY FOCUS	Refurbishment Uprating
SUMMARY	The simultaneous uprating and refurbishment of plants makes more economic sense. Such an approach is proposed for the 30-year old Ybbs-Persenberg plant on the Danube. The installation of a new unit at the same time as refurbishment will be lead to cost savings in the order of US$50 million. Authors affiliated with Danube Hydro Austria.

V 3.12

TITLE	**Control specification-paraphrasing: a methodology for successful retrofitting**
AUTHOR	Hoff, K. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.13

TITLE	**Cost and economics of hydroplant modernisation**
AUTHOR:	Castelli, B., Hartmann, O., and Ravicini,L **COUNTRY** Italy
PUBLICATION	*International Water Power & Dam Construction.* Vol. 45, No.12. p.47–55.
DATE	December 1993
KEY FOCUS	Electromechanical components Economic aspects Modernization
SUMMARY	Cost information and economics are essential for owners of older plants considering modernization. This paper presents a new methodology for the economic evaluation of modernization projects concentrating on comparative cost data for major plant components. Extensively supported by charts and tables. Authors affiliated with ABB Power Generation Ltd., Birr, Switzerland

V 3.14

TITLE	**Development of a continuous partial discharge monitoring system for hydrogenerator stators**
AUTHOR	Lloyd, B., Susnik, M., Phillips, J. and Stranovsky, G. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.15

TITLE	**Developments on hydrogenerator thrust bearings**
AUTHOR	Knox, R. T. **COUNTRY** UK
PUBLICATION	*International Journal on Hydropower & Dams*, Vol. 6, No. 3. p. 62–64.
DATE	1999
KEY FOCUS	Bearings New technology PTFE coatings
SUMMARY	The advantage of PTFE coating for hydrogenerator thrust bearings is its superior performance at high operation levels. This is the result of its low frictional properties and chemical inertness, which reduce the risks of failure associated with white metal coatings. This technical paper discusses the coating's condition after several years' operation at three power plants, and the full range of benefits realized.

V 3.16

TITLE	**Digital for AVR**
AUTHOR	Hopf, Dieter **COUNTRY** Austria
PUBLICATION	*International Journal on Water Power and Dam Construction*. Vol. 49, No. 1. p. 21–22.
DATE	January 1997
KEY FOCUS	Digital automatic voltage regulators Excitation systems
SUMMARY	The use of digital AVR for the refurbishment of 22 generators in seven hydro plants in Indonesia. A single standard excitation system was used. Author affiliated with Elin Energieversorgung, Vienna, Austria.

V 3.17

TITLE	**EL-CID test evaluation**
AUTHOR	Ridley, G.K. **COUNTRY** USA
PUBLICATION	*IEEE Power Engineering Journal*, II, p. 21–26, February 1997.
DATE	1997
KEY FOCUS	Generator tests

V 3.18

TITLE	**Electrical diagnostics for station equipment: the need for robust interpretation of monitoring data**
AUTHOR	Braun, J., Densley, R., Fujimoto, N., and Sedding, H. **COUNTRY** Canada
PUBLICATION	*Proceedings of the IEEE International Conference on Properties and Applications of Dielectic Materials*. Vol 1. IEEE, Piscataway, NJ. p. 198–200.
DATE	1997
KEY FOCUS	Conditioning monitoring Diagnostic tools
SUMMARY	Engineers at Ontario Hydro Technologies have developed a set of guidelines for using monitoring data effectively in preventive maintenance of power plant equipment.

V 3.19

TITLE	**Epoxy or polyester? The debate continues**
AUTHOR	Nailen, R. L. **COUNTRY** USA
PUBLICATION	*Electrical Apparatus*. p. 41–42.
DATE	August 1996
KEY FOCUS	Stator insulation Stator windings
SUMMARY	A comparison is drawn between the use of epoxy or polyester in the manufacture and design of generator stator windings. The paper presents the advantages and disadvantages of each insulation system.

V 3.20

TITLE	**Estimating the remaining service life of asphalt-Mica stator insulation**
AUTHOR	Timberly, J. E. and Michalec, J. R. **COUNTRY** USA
PUBLICATION	*IEEE Transactions on Energy Conversion*. Vol. 9, No. 4. p. 686–693.
DATE	December 1994
KEY FOCUS	Stator insulation Stator Windings
SUMMARY	The major failure modes of Asphalt-Mica insulation are outlined. American Electric Power's Rewind program is outlined, including test methods to aid in determining if a stator needs rewinding.

V 3.21

TITLE	**Evaluation of partial discharge detection techniques on hydro generators in the Australian Snowy Mountains Scheme – Tumut 1 case study**
AUTHOR	Tychsen, R. C. **COUNTRY** USA
PUBLICATION	*IEEE Power Engineering Society*, January 1994.
DATE	1994

V 3.22

TITLE	**Experience with PDA diagnostic testing on hydraulic generators**
AUTHOR	Lyles, J. F., Stone, C. S. and Kurtz, M. **COUNTRY** USA
PUBLICATION	*IE Aust and SMHEA Hydro Power Seminar,* Cooma. February 1988.
DATE	1988

V 3.23

TITLE	**Failure mode testing of a hydro generator equipped with a rotor-mounted scanner**
AUTHOR	Edmonds, J., Rasmussen, J., Campbell, T. and Stone, G. **COUNTRY** USA
PUBLICATION	*International Water Power and Dam Construction*. Vol. 45, No.1. p. 37–43.
DATE	January 1993
KEY FOCUS	Generator condition monitoring Rotor mounted scanner
SUMMARY	A detailed technical discussion of the use of the HydroScan rotor-mounted generator scanner in a failure mode test program at Boundary Powerplant, WA. Extensive use of colored thermal maps illustrate the test results and the system's capabilities. Authors affiliated with MCM Enterprises, WA, Seattle City Light, WA, and Iris Power Engineering, ONT. Recommended reading.

V 3.24

TITLE	**Getting the most out of existing generators: rehabilitation advances and advice**
AUTHOR	Wetmore, J. & Young, M. **COUNTRY** USA
PUBLICATION	*Hydro Review.* Vol XVII, No. 3. p. 10–14.
DATE	May 1993
KEY FOCUS	Contractual arrangements Generator rewinding New technology
SUMMARY	The authors draw on 10 years' experience to share their ideas about the importance of developing clear technical specifications for contractors carrying out a generator rewind. Recommendations are given about how the process should be approached, and a brief overview of advances in winding technology is provided. Author affiliated with Sacramento municipal Utility District Hydro Operations, Pollock Pines, CA.

V 3.25

TITLE	**Generator rewinds: a model to predict optimum timing**
AUTHOR	Westermann, G. D., Bhan, K. and de Meel, H. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.26

TITLE	**Grand stator affairs**
AUTHOR	Light, S. and White, E. **COUNTRY** USA
PUBLICATION	*International Waterpower and Dam Construction.* Vol. 49, No. 4. p. 26, 28.
DATE	1997
KEY FOCUS	Generator upgrading New technology State-of-art design Stators
SUMMARY	The state-of-the-art design of the Siemens components for the upgraded stators at the Grand Coulee plant provides an additional 105 MW of power with the same water usage and the same limitations of the turbine and generator. An innovative method of installation is expected to lead to cost savings of US$50M by completion of the project.

V 3.27

TITLE	**Guide to evaluate the need to rebuild hydro-electric generators**
AUTHOR	Yelle, R. and Mϑnard, P. **COUNTRY**
PUBLICATION	*Canadian Electrical Association (1999).* Electricity '99 Conference and Ex[position - "Technology for a changing industry." March 29–31 1999. Vancouver, British Columbia. Transactions. Part I, *CEA, Montreal, Q. 15p.*
DATE	1999
KEY FOCUS	Generator upgrading
SUMMARY	This guide presents a method of evaluating the options of rebuilding or maintaining generators. The method is based on the use of important technical signs and criteria to establish the condition of the components. Major components most vulnerable to deterioration, the stator winding, stator core, and the rotor are evaluated and graded according to their design and construction, history and the results of visual inspections and tests. Mechanical components, and external factors which could influence the condition of the generators or the order of rebuilding them are also evaluated. All tables used for evaluations, quantifying condition and formulating recommended actions are included.

V 3.28

TITLE	**The guide to hydropower mechanical design**
AUTHOR	ASME Hydro Power Technical Committee **COUNTRY** USA
PUBLICATION	*The guide to hydropower mechanical design*. (1996) HCI, Kansas City, (400p).
DATE	1996
KEY FOCUS	Generator testing State-of-art design
SUMMARY	An outstanding reference to SOA design of hydromechanical equipment and auxiliary mechanical systems, and a guide to the environmental, layout, maintenance and operation considerations of hydro plants, hydraulic transients, inspection, and testing. Includes section on generators.

V 3.29

TITLE	**Handbook of electrical and electronic insulating materials**
AUTHOR	Snugg, W. and Tillar **COUNTRY** USA
PUBLICATION	*IEEE Press,* Shugg Enterprises Inc. 1995. ISBN 0-7803-1030-6.
DATE	1995
KEY FOCUS	Insulation

V 3.30

TITLE	**Handbook to assess rotating machinery insulation condition**
AUTHOR	EPRI Power Research Institute **COUNTRY** USA
PUBLICATION	*EPRI EL-5036.*
DATE	1987
KEY FOCUS	Generator design Generator testing Insulation

V 3.31

TITLE	**High voltage power generation without transformers**
AUTHOR	Leijon, M. Berggren, B. and Owman, F. **COUNTRY** USA
PUBLICATION	*International Journal of Hydropower & Dams,* Issue 4, 1998.
DATE	1998
KEY FOCUS	Generators New Technology Generator Transformers
SUMMARY	Details the technical features of ABB's new generator that generates power directly at transmission grid voltages.

V 3.32

TITLE	**High voltage: the story behind the high-voltage generator from ABB**
AUTHOR	Ulvsgard, J. (ed) **COUNTRY** Sweden
PUBLICATION	*High voltage: the story behind the high voltage generator from ABB*, ABB Generation AB: Västeräs, Sweden. Supplement to *Hydro Review Worldwide* Vol. 6, No. 4. 11p.
DATE	September 1998
KEY FOCUS	Generator design New technology State-of-art design
SUMMARY	A series of articles on the development and features of ABB's state -of-art high-voltage Powerformer™, which can be used in retrofits as well as new plants. Benefits include overall improvement in efficiency, better opportunity for reactive power, lower maintenance costs, and a number of environmental benefits. The electrical system is free from partial discharges, for example, and consequently no ozone is produced.

V 3.33

TITLE	**Hydro-electric generator ozone monitoring**
AUTHOR	Franklin, D., Pollock, B. and Laakso, J. **COUNTRY** Canada
PUBLICATION	*Waterpower '93. Proceedings of the International Conference on Hydropower* (1993). Vol. 3. ASCE, New York. p. 1767–1776.
DATE	1993
KEY FOCUS	Ozone monitoring
SUMMARY	The presence of ozone in relatively high concentrations is both a health and safety concern and an indicator of faults within generator winding, insulation and brush gear systems. Powertech Labs, BC, with support from BC Hydro and CEA, developed an on-line Machine Monitoring System to monitor machine condition in the sense of corona discharge. The emphasis was on the use of commercially available technology. This technical article details the features, technology, testing and anticipated future developments of the system. Extensively illustrated. Authors affiliated with Powertech Labs, Surrey, BC and BC Hydro.

V 3.34

TITLE	**Hydroelectric generators: repair or refurbishment?**
AUTHOR	Whiteoak, N. and Jeannez, P. **COUNTRY** General
PUBLICATION	GEC Review, Vol. 12, No. 1.
DATE	1997
KEY FOCUS	Economic aspects Generator refurbishment New technology Stators
SUMMARY	A planned program of refurbishment will lead to economic and output advantages that an unplanned repair program will not. The reasons that machines fail, methods of diagnosing their condition and enhancing performance, and the need to use state-of-the art replacement components are discussed. Examples of refurbishment in a typical project are detailed and suggestions given for less conservative means of exploiting the potential for upgraded equipment. Authors affiliated with GEC Alsthom UK & France.

V 3.35

TITLE	**Hydrogenerator design for refurbishment**
AUTHOR	Ridley, G.K. **COUNTRY** UK
PUBLICATION	*International Water Power & Dam Construction*. Vol. 44, No. 5. p. 29–32.
DATE	May 1992
KEY FOCUS	Generators Refurbishment
SUMMARY	A review of developments and progress in the field of hydrogenerator refurbishment focusing on the basis for, and limitations and optimization of, refurbishment design. A procedure for electromagnetic design assessment is included. Author affiliated with GEC Alsthom, UK.

V 3.36

TITLE	**Hydro generator refurbishment**		
AUTHOR	Sonstad, J.	**COUNTRY**	Norway
PUBLICATION	EB Power Generation.		
DATE			
KEY FOCUS	Generator evaluation Generator refurbishment		
SUMMARY	This article deals with the refurbishment and evaluation of hydro generators. It outlines the major components of the generator that need to be evaluated in order to determine the suitability for generator refurbishment and/or uprating.		

V 3.37

TITLE	**Hydro generator rewinds: planning for success**		
AUTHOR	Naeff, H.	**COUNTRY**	Switzerland
PUBLICATION	*Hydro Review*. Vol. 15, No. 3. p. 44–53.		
DATE	May 1996		
KEY FOCUS	Stator Rewinding		
SUMMARY	This peer-reviewed article presents guidelines for planning the rewind of hydroelectric generator stator windings. Includes suggestions for developing adequate rewind specifications. Author affiliated with Colenco Power Consulting, Baden, Switzerland.		

V 3.38

TITLE	**Hydro plant electrical systems**		
AUTHOR	Clemen, D.	**COUNTRY**	USA
PUBLICATION	Clemen, D. (1999). *Hydro plant electrical systems*, HCI, Kansas City, MO.		
DATE	1999		
KEY FOCUS	Electrical systems		
SUMMARY	An easy-to-read guide to hydroelectrical and control systems which focuses on the practical aspects of selection, installation testing, and maintenance. Comprehensive checklists and references are included.		

V 3.39

TITLE	**How does your turbine-generator rate?**
AUTHOR	Seely, D. and Sheldon, R. **COUNTRY** USA
PUBLICATION	*Hydro Review,* Vol. XVIII, No. 4, p. 70–73.
DATE	July 1999
KEY FOCUS	Generator rating
SUMMARY	Two hydro engineering experts respond to questions about generator nameplate ratings. Because Federal Energy Regulatory Commission (FERC) determines annual fees for licensed projects >1.5 MW, based on these ratings it makes economic sense to understand the importance of them. The ratings process the implications of exceeding designated thermal limits. The effect of power-factor on the rating and the in differences between induction and synchronous generators are covered. The discussion concludes with an explanation of how FERC uses equipment ratings when determining a project's authorized capacity, and it raises the issue of whether a change in the procedure is required to address the rating of variable speed generators.

V 3.40

TITLE	**IEEE guide for the commissioning of electrical systems in hydroelectric power plants**
AUTHOR	IEEE **COUNTRY** USA
PUBLICATION	Institute of Electrical and Electronic Engineers. Power Engineering Society Power Generation Committee (1998). *IEEE guide for the commissioning of electrical systems in hydroelectric power plants*. Report # 1248. IEEE, New York.
DATE	1998
KEY FOCUS	Electrical system standards
SUMMARY	Up-to-date revised guide to design and application of power plant electrical systems. Essential reference. New Standard Report.

V 3.41

TITLE	**IEEE guide for the rehabilitation of hydroelectric power plants**
AUTHOR	Power Generation Committee of the IEEE Power Engineering Society **COUNTRY** USA
PUBLICATION	*IEEE guide for the rehabilitation of hydroelectric power plants.* Standard report # 1147–1991. IEEE, New York, NY. 48 p.
DATE	1996
KEY FOCUS	Decision-making Electrical systems Generator rehabilitation Power plant control systems
SUMMARY	A guide to assist in decision-making and design for the rehabilitation of hydroelectric plants covering the assessment of the economic feasibility, the rehabilitation of generators, waterways and electrical equipment and a bibliography of standards, recommended practices, and guides.

V 3.42

TITLE	**The impact of reduced build stator bar insulation on vertical generator design**
AUTHOR	Draper, R. E. and Moore, B. J. **COUNTRY** USA
PUBLICATION	*International Journal of Hydropower & Dams,* Issue 1, 1998.
DATE	1998
KEY FOCUS	Generator insulation
SUMMARY	A Canadian generator manufacturer has been working to improve the performance and reduce the physical size of generators by focusing on a reduced build stator bar insulation system.

V 3.43

TITLE	**Implementation framework for an expert system for generator monitoring**
AUTHOR	Kezunovic, M., Rikalo, I, Sun, J., Wu, X., Fromen, C., Sevcik, D., and Tielke, K. **COUNTRY** USA
PUBLICATION	*ISAP '96. Proceedings of the International Conference on Intelligent Systems Applications to Power Systems*, IEEE, Piscataway, NJ. p. 140–144.
DATE	1996
KEY FOCUS	Expert systems Generator monitoring Software
SUMMARY	Describes the development, features and applications of the Generator monitoring Expert system, GENEX, a new application of an intelligent system for automated monitoring of the electrical part of a generator. Authors affiliated with Texas A&M University and Houston Power & Light, who have collaborated on the development of the software described.

V 3.44

TITLE	**Improving the performance of hydrogenerator thrust bearings**
AUTHOR	Ferguson, G. E. **COUNTRY** Canada
PUBLICATION	*Uprating and Refurbishing Hydro Power Plants VI. Montreal, 1997 Conference Proceedings*. International Water Power and Dam Construction, Sutton, UK. p. 259–268.
DATE	1997
KEY FOCUS	Bearings Generator condition monitoring Generator uprating New technology
SUMMARY	Advancements in technology now permit an accurate analysis of the hydrodynamic oilfilm on hydrogenerator bearings which can be used to improve design and performance of existing bearings. Different options for refurbishment are given, with examples. Author affiliated with GE Hydro, Canada.

V 3.45

TITLE	**Initial experience in the Snowy Mountains Scheme with the PDA and installation and use of permanent capacitative couplers on hydro generators**		
AUTHOR	Tyschen, R. C.	**COUNTRY**	USA
PUBLICATION	*Electrica/Electronic Insulation Conference,* Chicago, USA, September 1989.		
DATE	1989		

V 3.46

TITLE	**Innovative approaches to rehabilitation work**		
AUTHOR	Samuelian, M. and Rufin, R.	**COUNTRY**	USA
PUBLICATION	*Hydro Review*, Vol. XIX, No. 1, p. 10–14.		
DATE	February 2000		
KEY FOCUS	Generator upgrading		
SUMMARY	At Norfolk Dam Rehabilitation project, USACE engineers developed a method of replacing several cracked field pole connectors without having to remove the rotor from two generating units. A special tool was used to punch holes in the quarter-inch copper rotor, and the new braided copper connectors were attached with bolts instead of welds. In addition to addressing the problem of cracking, thought to be accumulation of centrifugal stress and a soldering induced damage to the metal. The new braided connectors carry an ampere rating of 2000. This additional capacity allows more currents to flow with less resistance and reduces the chance of overheating.		

V 3.47

TITLE	**"Listening" for changes: using ultrasound to check stator core tightness in a hydro generator**		
AUTHOR	Mazzocco, M.	**COUNTRY**	France
PUBLICATION	*Hydro Review Worldwide*. Vol. 6, No. 1. p. 36–37.		
DATE	March 1998		
KEY FOCUS	Generator condition monitoring New technology Stators Ultrasound		
SUMMARY	Electricité de France has used an innovative ultrasound technique to test generators for changes in tension at its 500 hydroelectric plants. The method avoids the disassembly of the units.		

V 3.48

TITLE	**Matching turbine and generator rotational speed**		
AUTHOR	Bernhardt, P. and March, P.	**COUNTRY**	USA
PUBLICATION	*Hydro Review,* Vol. XVIII, No. 3.		
DATE	June 1999		
KEY FOCUS	Generator upgrading		
SUMMARY	For many years Niagara Mohawk operated two of its turbines at Bennett's Bridge Hydro Station at 75 rpm less than their rating to match the rating of the two 300-rpm generators. Prior to a turbine runner upgrade, a study of options suggested that the matching speed could be increased to 360 rpm by reducing the number of rotor poles. The report describes the technical and economic analyses carried out, and the work undertaken on the runners and one generator. Capacity for the first unit upgraded increased from 7.3 MW to 9.8 MW, and a 6% relative gain in efficiency. Based on this success, the company proceeded with an identical upgrade on the second unit.		

V 3.49

TITLE	**MicroDAU: High Performance Data Acquisition for Hydroelectric Generator Machine Diagnostics**
AUTHOR	Hirschman, G. B., Bardsley, S., Walter, T., Zelingher, S., Stranovsky, G., Zelinski, A. and Krikorian, M. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.50

TITLE	**Modernizing control and excitation systems**
AUTHOR	Stach, W. and Reimann, M. **COUNTRY** Germany
PUBLICATION	*Water Power and Dam Construction.* Vol. 43, No. 10. p. 49–57.
DATE	October 1991
KEY FOCUS	Control systems Static excitation systems
SUMMARY	It makes sense to evaluate control systems at the same time as generating units are being refurbished or upgraded. Several approaches to the modernizing of control systems are presented. The Thyripol static excitation system is discussed in detail. Author affiliated with SiemensAG, Erlangen, Germany.

V 3.51

TITLE	**Monitoring the air gap**
AUTHOR	Major, C., Allen, G., and Houle. Y. **COUNTRY** Canada
PUBLICATION	*International Water Power and Dam Construction.* Vol. 50, No. 4. p. 40–41.
DATE	April 1998
KEY FOCUS	Air gap measurement Generator condition monitoring Stator monitoring
SUMMARY	The on-line VibroSystM air gap monitoring system, used by Hydro-Quebec to address stator deformation, allows rotor and stator monitoring while the generator is in operation. Data for air gap and stator before and after refurbishment is given.

V 3.52

TITLE	**Monitoring and diagnostic expert systems for hydro generators**
AUTHOR	CIGRE **COUNTRY**
PUBLICATION	CIGRE Working Group 02 of Study Committee 11. (1994). *Monitoring and diagnostic expert systems for hydro generators*. WG-11.02. 6 p.
DATE	1994
KEY FOCUS	Diagnostic expert systems Generator monitoring
SUMMARY	Findings of a CIGRE international questionnaire distributed to users, research institutes, manufacturers, and consultants on monitoring and diagnostic expert systems. Information was sought on the advantages of such systems; the areas of operational work in which such a system would be preferable; what expert systems are being developed; what tasks they perform; what price would be acceptable.

V 3.53

TITLE	**Monitoring techniques aid in preparing for unit refurbishment**
AUTHOR	Venne, P. and Bissonnette, M. **COUNTRY** Canada
PUBLICATION	*Hydro Review,* Vol. XVIII, No. 1, p. 62–63.
DATE	February 1999
KEY FOCUS	Air gap analysis New Technology
SUMMARY	Hydro-Quebec's use of on-line monitoring and testing of a turbine-generator unit prior to refurbishment revealed that the cause of long-standing vibration was related to the stator, not the rotor as had been assumed. The unexpected results led to quite different remedial actions, substantial cost savings, and the removal of the 85% load restriction which had been in place for many years.

V 3.54

TITLE	**Nantahala control upgrades provide cost savings**
AUTHOR	Neumeuller, S. and Wright, J **COUNTRY** USA
PUBLICATION	*Waterpower '97. Proceedings of the International Conference on Hydropower.* Vol. 1. ASCE, New York. p. 704–712.
DATE	1997
KEY FOCUS	Control systems Generator upgrading
SUMMARY	The upgrade of two generating units at the Queen's Creek and Nantahala powerhouses in North Carolina led to reduced costs.

V 3.55

TITLE	**On-line condition monitoring for generators**
AUTHOR	Edmonds, J. S. **COUNTRY** USA
PUBLICATION	*International Water Power and Dam Construction*. Vol. 46, No.10. p. 80–82.
DATE	October 1994
KEY FOCUS	Air gap measurement Generator condition monitoring Partial discharge analysis
SUMMARY	Technical article on the development, capabilities, and applications of the EPRI-developed scanner system of generator condition monitoring. Seattle City Light and TVA have used systems developed from it as part of their turbine upgrade programs. Illustrated with thermal and partial discharge before and after maps.

V 3.56

TITLE	**On-line partial discharge monitoring: where we stand and what next?**
AUTHOR	Warren, V. and Kantardziski, P. **COUNTRY** USA
PUBLICATION	*International Journal of Hydropower & Dams*, Issue 4, 1998.
DATE	1998
KEY FOCUS	Generator testing Stator windings
SUMMARY	The results of a study conducted by Iris Power Engineering to assess the state-of-the-art techniques of on-line partial discharge monitoring of hydro generators.

V 3.57

TITLE	**Operating characteristics of hydroelectric generating sets**
AUTHOR	Strongman, C. P. **COUNTRY** USA
PUBLICATION	*International Journal of Hydropower & Dams,* Issue 1, 1999.
DATE	1999
KEY FOCUS	Generators
SUMMARY	A graphical form of operating characteristics for a hydroelectric generating set is presented which can be used in the many applications that arise in the course of the study and implementation of a hydroelectric scheme. This paper considers the steady-state characteristics of water turbines and salient-pole generators and demonstrates how these can be combined to give the characteristics of a generating set as a whole.

V 3.58

TITLE	**Preparing for the twenty-first century: environmental protection, efficiency**
AUTHOR	Fulton, E. **COUNTRY** North America
PUBLICATION	*Hydro Review*. Vol XVII, No. 6. p. 10–12.
DATE	November 1998
KEY FOCUS	Environmental protection Greaseless bushings New technology
SUMMARY	New technologies are emerging which improve efficiency and environmental performance of generating equipment. This paper presents a report on a survey of North American hydro operators about their experiences in implementing such technologies as greaseless bushings, oil-less (electric) governors and fish friendly turbine generators.

V 3.59

TITLE	**Problems associated with large generators**
AUTHOR	Lyles, J. F. and Goodeve, T. E. **COUNTRY** USA
PUBLICATION	*Proceedings of Water Power '89.* ASCE, 1989.
DATE	1989
KEY FOCUS	Generator design Generator rehabilitation

V 3.60

TITLE	**Raising the temperature**
AUTHOR	**COUNTRY** Canada
PUBLICATION	*International Water Power and Dam Construction*. Vol. 49, No. 7. p. 34.
DATE	July 1997
KEY FOCUS	Partial discharge Stator life extension Stators
SUMMARY	Engineers studying performance at BC Hydro's John Hart plant, have found that operating the stator at temperatures at the higher end of their design range dramatically reduces the chance of partial discharge. Overcooling the stator produces 10 times the amount of PD than when running it at a higher temperature. Plant staff attribute the discovery to the use of on-line monitoring condition equipment. Advantages of the new operating regime include prolonging the life of the stator and increasing plant efficiency. Tables illustrate the study findings.

V 3.61

TITLE	**Real-time loss measurement on generators at site by retardation method**
AUTHOR	Woschnagg, E. **COUNTRY** Austria
PUBLICATION	*Uprating and Refurbishing Hydro Plants IV. Conference Papers.* (1993). International Water Power and Dam Construction: Sutton, UK. p. 301–309.
DATE	1993
KEY FOCUS	Generator testing New technology
SUMMARY	A technical paper which discusses the features of a new Digital Speed Analyzer which differentiates the speed in real-time and thus makes the evaluation of speed-power curves instead of speed-time curves feasible, allowing the power at rated speed to be determined with more accuracy. The features of the system, its advantages, and other applications are detailed and extensively supported with graphs. Author affiliated with ELIN Energieversorgung, Weiz, Austria.

V 3.62

TITLE	**Refurbishing generators puts pressure on cooling**
AUTHOR	Fenwick, G. **COUNTRY** Canada
PUBLICATION	*International Water Power and Dam Construction*. Vol 49, No. 1. p. 17–20.
DATE	January 1997
KEY FOCUS	Generator cooling systems
SUMMARY	A cooling system for an uprated generator must dissipate more kW, but is limited to the size and flow of the constraints of the old generator. The author, affiliated with Unifin, London, ONT., presents a comprehensive list of design considerations.

V 3.63

TITLE	**Refurbishment and uprating of Tumut 1 and Tumut 2 power stations: a case study**
AUTHOR	Whitby, R. **COUNTRY** Australia
PUBLICATION	*Uprating and Refurbishing Hydro Power Plants V Conference Proceedings.* (1995). International Water Power and Dam Construction, Sutton, UK. n.p.
DATE	1995
KEY FOCUS	Generator refurbishment Generator uprating
SUMMARY	The predicted imminent failure of the stator windings prompted this AU$50 million project. Studies also indicated that the generators could be uprated by 20% for little extra cost and that efficiency and capacity gains could be achieved by upgrading the turbine runners. This 23-page report details the technical aspects of the upgrading and how technical and contractual/management problems were overcome.

V 3.64

TITLE	**Rehabilitating Grand Coulee's generators: fast turnarounds, heavy lifting**
AUTHOR	Hamilton, S. **COUNTRY** USA
PUBLICATION	*Hydro Review*. Vol. XVII, No. 2. p. 32–35.
DATE	April 1998
KEY FOCUS	Economic aspects Generator rehabilitation Project planning
SUMMARY	The innovative approach taken to the rehabilitation of the Grand Coulee's generators dramatically reduced outage time and resulted in a net benefit of an estimated US$59 million in comparison with costs of traditional methods. Author affiliated with Resource Associates International.

V 3.65

TITLE	**Repair and Replacement Considerations for Old Hydrogenerator Stator Cores**
AUTHOR	Moore, W. G. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.66

TITLE	**Rotor-mounted scanners safeguards stators**
AUTHOR	EPRI **COUNTRY** USA
PUBLICATION	www.epriweb.com, Environmental Group, Hydro Plant News, Fall 1997.
DATE	1997
KEY FOCUS	Generator monitoring systems
SUMMARY	Details on the rotor mounted scanner, an on-line system developed by EPRI 10 years ago to monitor and trend the electrical, mechanical and magnetic status of a stator with each pass of the rotor.

V 3.67

TITLE	**Solving a vibration problem in a stator**
AUTHOR	McLaughlin, B and Seyler, J. **COUNTRY** Canada
PUBLICATION	*Hydro Review*. Vol. XV, No. 3. p. 60–61.
DATE	May 1996
KEY FOCUS	Stators Vibration
SUMMARY	The stator of Unit 2 at the Spray Generating Station, developed excessive vibration problems following a stator rewind and generator uprating. The paper outlines the methodology used to find the cause of the vibration as well as the steps taken to correct the problem. Authors affiliated with TransAlta Utilities Corp., Alberta, and Westinghouse, ONT.

V 3.68

TITLE	**Stator core assembly: choosing methods that fit the site**
AUTHOR	Clemen, D. and Zamova, C. **COUNTRY** USA
PUBLICATION	*Hydro Review,* Vol. XVIII, No. 6, p. 57–61.
DATE	October 1999
KEY FOCUS	Stator
SUMMARY	This paper emphasizes the need to consider project-specific factors before determining the method and location of assembling anew stator core in situ. Transport implications related to various generator types are discussed briefly, prior to a more detailed summary of the advantages and disadvantages of assembling core sections shipped from the factory, or stacking the coves at the site. Labor availability, integrity of the assembly, time constraints, space requirements, and the risk of contamination must all be taken into account. A table lists examples of generator installations and the rationale for the selected method of their stator assembly.

V 3.69

TITLE	**Study of benefits of powerformer in a hydro power plant installation**
AUTHOR	Palmer, S., Bjerhag, H., Sjolander, L., Bjorklund, L., Frost, P., and Parkegren, C. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.70

TITLE	**A systematic approach to developing a condition monitoring system**
AUTHOR	PB Power Inc. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.71

TITLE	**Temperature and thrust bearing wiping incident reductions by use of a high viscosity index turbine oil**
AUTHOR	Okazaki, M. E. and Militante, S. E. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.72

TITLE	**Thrust bearing failures - common sense solutions: Little Long Generation Station**
AUTHOR	Khoral, P. and Schaefer, P. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

V 3.73

TITLE	**Turning it on-line**
AUTHOR	Kotlica, M. **COUNTRY** Canada
PUBLICATION	*International Journal of Water Power & Dam Construction*. Vol. 49. No. 7. p. 36–38.
DATE	July 1997
KEY FOCUS	Partial discharge analysis Software Stator winding
SUMMARY	A description of the of the KES portable partial discharge analyzer which uses Windows-based software for on-line monitoring of generators and other electromechanical components. The system is flexible in allowing for different operation modes and test results in different formats. Paper illustrated with typical program screen and other comparative result tables. Author affiliated with KES Ltd. International, Ontario, Canada.

V 3.74

TITLE	**Upgrading the excitation system: one step towards ultimate station reliability**
AUTHOR	Hopf, D. **COUNTRY** Austria
PUBLICATION	*Uprating and Refurbishing Hydro Powerplants V. Conference Proceedings. Nice, France 9–11 October, 1995.* International Water Power and Dam Construction, Sutton, UK. n.p.
DATE	1995
KEY FOCUS	Excitation systems
SUMMARY	Two projects are used to demonstrate appropriate refurbishment strategies for generator excitation systems. The advantages of digital voltage regulators are discussed. Author affiliated with Elin Energieversorgung, Vienna, Austria.

V 3.75

TITLE	**Using diagnostic technology for identifying generator winding maintenance needs**
AUTHOR	Lyles, J., Goodeve, T. and Stone G. C. **COUNTRY** Canada
PUBLICATION	*Hydro Review*. Vol. XII, No. 4. p. 58–67.
DATE	June 1993
KEY FOCUS	Generator condition Monitoring Partial Discharge Analysis Stator Windings
SUMMARY	The paper focuses on the use of PD analysis as a maintenance and monitoring tool for generator stator windings. Emphasis is placed on the use of PDA to detect abnormal winding conditions, which can then be repaired before an entire stator rewind is necessary. Some background information is given explaining what the PD test is and how it works. Case studies are given for several generators where PDA was used to diagnose winding deterioration in an early stage that allowed subsequent repair of the winding. G.E. Armstrong Enterprises, Pickering, ONT.

V 3.76

TITLE	**VIMOS condition monitoring for hydropower machines**
AUTHOR	Eriksson, K. and Eriksson, S. **COUNTRY** Sweden
PUBLICATION	*ABB Review*. No. 1. p. 15–20.
DATE	1992
KEY FOCUS	Generator condition monitoring New technology Software
SUMMARY	A new condition monitoring system developed to address the need for mechanical protection of hydropower generator-turbine sets. The features of the system and its future development are described. Authors affiliated with ABB Generation, Vaesteraas, Sweden.

V 3.77

TITLE	**Who needs a transformer?**
AUTHOR	Moxon, S. **COUNTRY**
PUBLICATION	*International Water Power and Dam Construction.* Vol. 50, No. 4. p. 34–35.
DATE	April 1998
KEY FOCUS	Generator design Generator transformers New technology State-of-art design
SUMMARY	ABB has launched the world's first high-voltage (HV) generator, Powerformer, which will be installed for the first time at the Porjus hydro power plant in Sweden. The main development in the HV generator is that round, HV cables have replaced the square copper conductors that form the stator winding of a conventional generator.

V 3.78

TITLE	**A work management system based upon risk and reliability-centered maintenance**
AUTHOR	Judge, D. and Lundhild, V. **COUNTRY** USA
PUBLICATION	*HydroVision 2000 Conference Technical Papers*, August 8–11, 2000, Charlotte, North Carolina, HCI Publications Inc., Kansas City, MO.
DATE	August 8–11, 2000

IEEE Standards

Electric Machinery

43-2000 *IEEE Recommended Practice for Testing Insulation Resistance of Rotating Machinery.*

56-1977 *(R1991) IEEE Guide for Insulation Maintenance of Large Alternating-Current Rotating Machinery (10000 kVA and Larger).*

60-1990 *IEEE Guide for Operation and Maintenance of Turbine Generators.*

95-1977 *(R1991) IEEE Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage.*

100-1996 *Dictionary of Electrical and Electronic Terms.*

115-1995 *IEEE Guide: Test Procedures for Synchronous Machines, Part 1 Acceptance and Performance Testing, Part II Test Procedures and Parameter Determination.*

275-1992 *IEEE Recommended Practice for Thermal Evaluation of Insulation Systems for Alternating-Current Electric Machinery Employing Form-Wound Preinsulated Stator Coils for Machines Rated 6900 V and Below.*

286 *Recommended Practice for Measurement of Power Factor Tip-up of Rotating Machinery Stator Coil Insulation.*

304-1977 *IEEE Test Procedure of Evaluation and Classification of Insulation Systems for DC Machines.*

429-1994 *IEEE Recommended Practice for Thermal Evaluation of Sealed Insulation Systems for AC Electric Machinery Employing Form-Wound Preinsulated Stator Coils for Machines Rated 6900V and Below.*

433-1974 *IEEE Recommended Practice for Insulation Testing of Large AC Rotating Machinery with HIgh Voltage at Very Low Frequency.*

434-1973 *(R1991) IEEE Guide for Functional Evaluation of Insulation Systems for Large High-Voltage Machines.*

492-1999 *IEEE Guide for Operation and Maintenance of Hydrogenerators.*

522-1992 *IEEE Guide for Testing Turn-to-Turn Insulation on Form-Wound Stator Coils for Alternating-Current Rotating Electric Machines.*

792-1995 *IEEE Recommended Practice for the Evaluation of the Impact Voltage Capability of Insulation Systems for AC Electric Machinery Employing Form-wound Stator Coils.*

1043-1996 *IEEE Recommended Practice for Voltage-Enhance Testing of Form-Wound Bars and Coils.*

1129-1992 *IEEE Recommended Practice for Monitoring and Instrumentation of Turbine Generators.*

1310-1996 *IEEE Trial Use Recommended Practice for Thermal Cycle Testing of Form-Wound Stator Bars and Coils for Large Generators.*

Power Generation

125-1988 (R1996) *IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators.*

421.1-1986 (R1996) *IEEE Standard Definitions for Excitation Systems for Synchronous Machines 24 pages.*

421.2-1990 *IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems.*

421.3-1997 *IEEE Standard for High-Potential Test Requirements for Excitation Systems for Synchronous Machines.*

421.4-1990 *IEEE Guide for the Preparation of Excitation System Specifications.*

450-1995 *IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications.*

484-1996 *IEEE Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Stationary Applications.*

485-1997 *IEEE Recommended Practice for Sizing Lead-Acid Batteries for Stationary Applications.*

505-1977 (R1991) *IEEE Standard Nomenclature for Generating Station Electric Power Systems*.

665-1995 *IEEE Guide for Generating Station Grounding.*

666-1991 (R1996) *IEEE Design Guide for Electric Power Service Systems for Generating Stations.*

946-1992 *IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations.*

1010-1987 (R1992) *IEEE Guide for Control of Hydroelectric Power Plants.*

1020-1988 (R1994) *IEEE Guide for Control of Small Hydroelectric Power Plants.*

1046-1991 (R1996) *IEEE Application Guide for Distributed Digital Control and Monitoring for Power Plants.*

1050-1996 *IEEE Guide for Instrumentation and Control Grounding in Generating.*

1095-1989 (R1994). *IEEE Guide for Installation of Vertical Generators and Generator Motors for Hydroelectric Applications.*

1106- 1987 *IEEE Recommended Practice for Maintenance, Testing and Replacement of Nickel-Cadmium Storage Batteries for Generating Stations and Substations*.

1147-1991 (R1996) *IEEE Guide for the Rehabilitation of Hydroelectric Power Plants.*

1249-1996 *IEEE Guide for Computer-Based Control for Hydroelectric Plant Automation.*

1375-1998 *IEEE Guide for the Protection of Stationary Battery Systems.*

IEC Standards

60076-8 (1997-11) *Power Transformers.*

60085 (1984-01) *Thermal Evaluation and Classification of Electrical Insulation.*

60545(1976-01) *Guide for Commissioning, Operation and Maintenance of Hydraulic Turbines.*

61116 (1992-10) *Electromechanical Equipment Guide for Small Hydroelectric Installations.*

ANSI Standards

C50.10 (1990) *American National Standard for Rotating Electrical Machinery Synchronous Machines.*

C50.12 (1989) *Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications, Requirements for Salient Pole Synchronous.*

ASTM Standards

ASTM D4496	*Test Method for D-C Resistance or Conductance of Moderately Conductive Materials.*
ASTM A34-96	*Practice for Sampling and Procurement Testing of Magnetic Materials.*
ASTM A343-97	*Test Method for Alternating-Current Magnetic Properties of Materials at Power Frequencies Using Wattmeter-Ammeter-Voltmeter meter and 25-cm Epstein Test Frame.*
ASTM A717-95	*Test Method for Surface Insulation Resistivity of Single-Strip Specimens.*
ASTM A937-95	*Test Method for Determining Interlaminar Resistance of Insulating Coatings Using Two Adjacent Test Surfaces (Franklin Test).*
ASTM D3276-96	*Guide for Painting Inspectors.*
ASTM D3359-95a	*Test Methods for Measuring Adhesion by Tape Test.*

NEMA Standards

NEMA MG 5.1 *Large Hydraulic Turbine-Driven Synchronous Generators.*
NEMA MG 5.2 *Installation of Vertical Hydraulic Turbo-Driven Generators.*

B
PROCUREMENT GUIDES

Procurement guides and sample specifications included in Appendix B:

1. A Guide for Stator Core Specifications, by Bruce Lonnecker of the U.S. Bureau of Reclamation for a Doble Client Conference

2. A Guide for Stator Winding Specifications, by Bruce Lonnecker of the U.S. Bureau of Reclamation for a Doble Client Conference

3. Sample Specifications (Outline) - Generator Stator Rehabilitation

The guides and sample specifications were developed for particular applications. They should not be treated as definitive guidelines for contract preparation. However, they contain useful details and flag topics that should be considered when drafting technical specifications for stator cores, windings, and rehabilitation work.

A Guide for Stator Core Specifications

Bruce Lonnecker
U.S. Bureau of Reclamation

Introduction

The following is a purchase specifications for stator laminations. The paper is a compiled specification for a stator taken from specifications by various committee members.

The report will discuss the scope and use of the specifications, our experiences at U.S. Bureau of Reclamation with stator replacement, and quality control.

Specification guides can be useful but they can also have built-in pitfalls when the reason for each requirement is not understood. The requirements in a paragraph are generally written with a range and type of equipment in mind.

The Bureau of Reclamation's generator paragraphs were written for mid- to large-sized hydrogenerators, to be supplied by large manufacturers with sophisticated tools. We have used them, with modifications, to specify smaller generators and synchronous motors. Likewise, the authors of the stator paragraphs contributed by the other nine utilities had a category of equipment in mind when their specifications were written. An attempt was made to keep as much of each as possible without repeating. This means that each paragraph is written as broadly as possible, and this should be considered with respect to the type and size of machine involved. The specifications were also written to adapt to work on a rewound, uprated, or new machine. There are some endnotes to help in the proper application.

Stator

a. General. - The Contractor shall design, furnish, and install a new stator core, incorporating the best modem practice in design, material, and workmanship. The Contractor shall design, manufacture, and install the stator in a manner that ensures the stator is round and, within reasonable limits, concentric with the rotor to avoid excessive air gap variations and unbalanced magnetic pull. Means shall be provided to prevent collapsing or buckling of the stator laminations due to thermal expansion or magnetic forces. The new stator core shall be designed so that the maximum temperature rise shall not exceed 55°Cas measured by the thermometer method or thermocouples above a 40°C ambient, while the generator is producing rated power.

The core of the generator shall be built up with high-grade, non-aging, thin, laminated silicon steel. After punching or cutting, each lamination shall be deburred and coated on both sides with a uniform and consistent coating of insulating varnish to minimize eddy current losses.

Air ducts shall be provided between packets of laminations for purposes of cooling. The air ducts in the stator core shall be arranged to make the flow of air smooth and quiet, to minimize air friction losses, and to make use of the existing generator air cooling system. Core teeth greater than 1.5 inches (38.10 mm) wide at the tip shall have two air duct spacer beams per tooth.

The laminations shall be adequately keyed or dovetailed to the stator frame by means of key bars and securely held in place by clamping flanges at each end. The Contractor shall design the key bars and select the material to withstand short circuit torque, unbalanced magnetic pull, and faulty synchronizing torque.

The clamping flanges may have integral or separate fingers. The fingers shall be held in place by the clamping action and by dowels, pins, grooves, or combinations thereof. The fingers of the clamping flanges shall be solid, (nonlaminated) nonmagnetic metal having a permeability of not more than three under any possible loading condition and shall be of sufficient length and rigidity to prevent looseness of the lamination teeth, especially at the top and bottom of the stator. The temperature rise of the fingers of the clamping flanges shall not exceed the temperature rise limit permitted for any nearby mechanical or electrical components.

As an alternative to the clamping flanges required above, the clamping force may be transmitted by the outer or end packet of core laminations that shall be bonded together at a pressure exceeding the core-operating pressure with a thermal-setting adhesive.

The Contractor shall furnish the lesser of 2000 or 5% of the total number of laminations as spares for one unit. Additionally, the Contractor shall provide two spares of all other stator components supplied. Other core spare parts would include laminations in the stepped back portions of the core, clamping fingers, key bars, and air vent spacer lamination plates, if applicable. The spare parts shall be delivered to the Owner upon completion of the last unit and shall be packaged and marked for extended storage.

b. Contractor-Provided Stator Drawings, Data, and Material Sample. - The Contractor shall provide the following information and material for review and approval prior to manufacture:

(1) Name of company and location where the laminations and other components are to be manufactured.

(2) Stator calculations, manufacturing schedule, installation procedure, and full load operating core flux.

(3) Tolerances for circularity, verticality, and height to which the stator core will be built and installed and how these parameters will be measured and/or monitored during installation.

(4) Drawings shall show:

- dimensions of each type of lamination to be installed

- overlapping lamination design so that joints do not line up on consecutive levels

- connection of laminations to the frame

- clamping flanges, if provided

(5) Materials list for the stator laminations, including type and thickness of steel to be used, type and thickness of insulation, description of the manufacturing process, and maximum allowable burr height before and after deburring.

(6) Key bar design calculations, materials, and installation procedures.

If the key bars are bolted to the stator frame, the Contractor must provide detailed calculations showing that the mechanical integrity of the key bar to stator frame will not be compromised by the maximum forces that the bolted coupling might encounter.

If the key bars are welded to the stator frame, the Contractor must provide detailed welding procedures for attaching the key bars and information on how and when the welding is performed. The Contractor shall provide detailed calculations showing the stresses involved at the key bar to stator frame welds and how they relate to the maximum stresses encountered.

If the key bars are designed to be restrained by a dovetail guide (retaining plate), which is welded to the frame, the Contractor shall provide design calculations for the key bar to dovetail system showing the stresses expected in the key bar to dovetail connection and how they relate to the maximum stresses possible. The Contractor shall provide a detailed installation and welding procedure.

(7) Clamping bolt design tension and nut torques necessary to hold the laminations to the required tightness. The calculations that indicate that the stresses are within design limits for the materials used shall be provided.

(8) Confirmation that stator bore is sized to permit the removal of turbine parts and lower bearing.

(9) Volts per turn required to produce full load flux for the required interlaminar insulation test.

(10) Sample of a previously manufactured lamination using a similar process to the process intended for this contract.

(11) Whether or not the stacked core will be seasoned (heated to aid in pressing). If the core is to be seasoned, the means of heating and the desired temperature and duration shall be specified. Precautions shall be taken to prevent warping of the core.

c. Manufacture. - The Contractor shall manufacture the components incorporating the best modern practice in materials and workmanship. The laminations may be die cut or laser cut. The laminations shall be securely crated for the chosen transportation means and protected from contamination or corrosion.

Following completion of the lamination punching by the Contractor, the punching dies shall be cleaned, sharpened, satisfactorily crated, and delivered the location indicated by the Owner. The die shall become the property of the Owner.

d. Factory Testing. - Factory tests shall be performed on the laminations to confirm the integrity of the insulating material and steel. Tests shall be performed on a sample lot at three periods during the manufacturing of the laminations: (1) at the beginning of the manufacturing process with the first few laminations produced, (2) approximately in the middle of the manufacturing process, and (3) upon completion of the manufacturing of the laminations. A sufficient number of laminations shall be selected to adequately perform the following test during each test period. Field testing includes a list of the required tests to be performed by the Contractor.

e. Installation. - The stator core shall be installed according to the installation procedure. As the laminations, top and bottom finger plates, dovetail bars, and through-bolts are removed, records shall be made as necessary to facilitate and orient installation of the new core material. The Contractor shall take care in removal not to damage the existing generator components such as the stator frame or generator coolers. Any damage to the generators shall be repaired to the satisfaction of the Owner by the Contractor and at the Contractor's expense.

The existing stator core and associated materials to be discarded shall become the property of the Contractor and shall be disposed of properly at the expense of the Contractor and as required by all applicable laws. A list shall be submitted to the Owner indicating the disposal site of all discarded materials. Laminations removed shall not be reused in the generators. Immediately following the complete removal of the existing core, the Contractor shall measure the stator frame for plumbness and a uniform symmetrical overall diameter. The final measurement values shall be forwarded to the Owner with any deviations from true brought to the Owner's attention. The cost of any work deemed necessary by the Owner to restore roundness or plumbness to the stator frame or the work to center the stator frame will be negotiated separately over and above the contract price.

f. New Core Steel Installation. - The Contractor shall fully prepare the unit for recoring. The Contractor shall furnish and install necessary temporary scaffolding and work platforms. The core shall be stacked in place and shall be designed so as to eliminate all split joints. Prior to stacking, all preparation work shall be completed and the area thoroughly cleaned. Each lamination or group of laminations shall be examined for shipping damage. Any laminations with burrs of excess height shall be discarded. Only smooth clean surfaces within the coil slots will be accepted. The completed stator core shall be clamped, through-bolts properly torqued, and through-bolt locking systems restored. Bolts shall have no marks on them prior to use.

To insure uniform tightness of laminations, full and final clamping pressure shall be applied to the successive layers of laminations while stacking progresses. This shall consist of at least two intermediate presses and one final press at equal spacing. Core tension shall be checked and will be determined to be tight when a 0.003-inch (0.076 mm) feeler gauge cannot be inserted into any corners of the core teeth. There shall not be any waves in the stacked laminations. Bolt torques shall be recorded and compared with design values to confirm that material strengths have not been exceeded.

The Contractor shall connect the existing generator cooling system to the new stator core and, upon completion of the generator reassembly, verify that the generator cooling system operates adequately with the new stator winding and core. All material and labor required to make the generator cooling system operational for the new stator are the responsibility of the Contractor.

A dimensional check of the verticality, levelness, circularity, and height of the bore shall be carried out at eight points halfway up the iron and at each end. Measurements are to be compared with stated tolerances and submitted to the Owner.

All equipment furnished by the Contractor and not permanently installed in the generator shall remain the property of the Contractor and be removed from the site by the Contractor.

g. Field Testing. - The following tests shall be performed by the Contractor upon completion of the core stacking.

Interlaminar Insulation Test - An interlaminar insulation test as outlined in Section 8.1.10 of lEEE Standard No. 56 shall be performed on the stator cores before the windings are installed. The Owner will provide a source for supplying the core magnetizing current. The core shall be magnetized to the full load flux value. The Contractor shall continuously monitor stator temperatures during the entire heating procedure to prevent damage or warping of the core.

After the core has been under excitation for a period of time, not less than 15 minutes, so that hot spots are distinguishable from the rest of the core, it shall be surveyed by infrared scanning with a device capable of detecting a difference in temperature of 0.5°C. The scanner provided shall be General Electric Thermalvision or approved equivalent. Polaroid photos or videotapes of the infrared device screen of hot spots (with absolute and differential temperatures indicated) shall be submitted to the Owner.

Any hot spots (areas with temperatures exceeding 5°C above surrounding iron) or irregularities shall be repaired by a method approved by the Owner, and the interlaminar test shall be rerun until no hot spots exist. After successful completion of this test, the core clamping studs shall be rechecked to insure that the tightness of the core has not relaxed.

Following successful completion of the interlaminar insulation test, semi-conducting varnish shall be applied to the stator core coil slots.

The following paragraphs relate to the stator paragraph.

WARRANTED CHARACTERISTICS (Located in bid schedule)

The Offeror warrants that the overall efficiency of each generator will be at least as high as stated below (see provision in subsection _____, “Failure to Meet Performance Warranties.” The Offeror also warrants that the capacity of the generator will not be less than the capacity rating stated under Item 1 of the bidding schedule.

a. Efficiency when operating at rated capacity. . . . _____*Offeror’s warranted efficiency

* Offers failing to indicate the above value will not be considered for award. Offers warranting an efficiency less than % will not be considered for award. (---)

(--) - Determination of Temperature Rise. (Located in warranty testing paragraph) - Heat runs shall be made to determine the temperature rise of the various parts of the generator at rated capacity. The temperature rise of the armature winding shall be determined by the embedded detector method, and the temperature rise of the field shall be determined by the resistance method. The average temperature, indicated by the highest reading temperature detector during the period of constant temperature, shall be used to determine the temperature rise of the armature winding and the core.

Determination of Efficiency. (Located in warranty testing paragraph) - Segregated losses shall be measured by the retardation method as described in Section 4.4 of IEEE Test Procedures for Synchronous Machines. The test value of WR shall be used in calculations to determine losses. Loss tests shall be made with the housing ambient temperature not exceeding the ambient for the rated load heat run under test, and with the waterflow to the bearing cooling coils unchanged from conditions during the heat run.

plus either

Curves shall be furnished of core losses versus voltage and stray-load loss versus armature current. The open-circuit core loss for the new stator core shall not be greater than that of the old stator core when tested.

or

Curves shall be furnished of core losses versus voltage and stray-load loss versus armature current. Overall machine efficiency shall be no less than the Offeror's warranted efficiency as stated in their proposal (see Warranted Characteristics in bid schedule).

Failure to meet the combined warranted armature J2 R, stray load, and core losses shall result in a price reduction in accordance with subparagraph "Failure to meet Performance Warranties."

Failure to Meet Performance Warranties. (Part of Quality Assurance Section) -

(1) The price of each generator will be reduced $_____ for each 1/100 of 1% that the actual efficiency is less than the warranted value stated under "Warranted Characteristics" in the bid schedule. The generator efficiency shall allow for all losses including windage, friction, core, stray, 12 R, and rotating exciter losses.

(2) The price of each generator will be further reduced $_____ for each 1/100 of 1% that the actual kilowatt capacity is below the warranted capacity at rated voltage, frequency, and power factor, and within the specified temperature rise limits.

A Guide for Stator Winding Specifications

Bruce Lonnecker
U.S. Bureau of Reclamation

Introduction

The following is a purchase specifications guide for stator windings. The guide is compiled from 12 specifications given by various Doble clients:

Many of these Doble clients have offered their specifications for reference with the warning, "Use at your own risk!" That goes double for use of this guide.

The report attempts to list most requirements from each of the contributed specifications without duplication. The contributed specifications were written for a variety of different types and sizes of machines, for rewinds and uprates, and for different installation requirements. For that reason, no attempt was made in the compilation to determine which requirements were best. Instead, the most common or detailed requirements are shown, and the less common requirements are indicated in the endnotes. This method caused the guide to also evolve into a survey of the Doble clients' specifications requirements.

Therefore, the guide is to be used for most stator winding applications with appropriate modifications for the specific machine type and company policy. For more information about specific applications and policies, many of the contributing Doble clients have offered their specifications as reference. Those documents are printed attached to this paper. Due to the volume of these attached specifications, they are not printed in the minutes. For copies of these specifications, please contact Doble or the author.

In order to standardize some wording, the words *coil*, *Owner*, *Contracting Officer*, and *Contractor* have been used in place of the words *coil*, *bar*, or *pair of bars*; *Purchaser*, *Company*, *District* or *Authority*; and *Engineer*, *Director*, *Inspector*; or *Representative*, respectively.

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DIVISION 1 - GENERAL REQUIREMENTS

1.1 SUMMARY OF WORK

The Contractor shall design, fabricate, furnish, deliver, install, and test, one complete Class "F" stator winding (including new circuit ring buses)[1] for generator unit(s) _____ at _____ Powerplant, in accordance with the requirements of these specifications. Also, the Contractor shall clean, test, and repair, if needed, retorque, treat stator slots, and paint the existing stator core iron. The Contractor shall furnish all manufacturing, materials, equipment, machinery, tools, supplies, labor, supervision, transportation, and perform all work necessary to complete the work. The materials shall include, but not be limited to, individual stator coils (top bars and bottom bars)[3],coil supports, slot packing material (including wedges), circuit rings, resistance temperature detectors and connections.

The existing generator will be disassembled and reassembled by the Owner; however, the Contractor shall remove the existing armature winding from the stator slots. The Contractor shall be responsible for appropriate disposal of the old stator winding and materials. (It is known that the old winding contains asbestos. The Contractor shall employ appropriate methods for cutting and packing of the old winding for removal.)[3]

The generator will be made available for inspection on _____ between the hours of _____ and _____. Inspection schedules shall be coordinated with the Project Manager, _____ at _____ (telephone number).

1.2 LOCATION, TYPE, RATING, HISTORY, AND INSPECTION

The _____ Powerplant is located immediately downstream of _____ Dam on the _____ River in _____ County _____, approximately _____ miles _____ from the town of _____. The main generator floor is at an elevation of _____ feet above sea level.

The existing generator(s) are of the vertical-shaft, waterwheel-driven,[4] alternating current, synchronous type.

The existing generator(s) have a nameplate rating of _____ kilovolt amperes, at _____ volts, _____ power factor, and 60 Hz (hertz).

The generator(s) were manufactured and installed by _____ company in _____ (year). The generator(s) (were rewound in _____ and) have been in continuous operation since installation. The winding has experienced significant deterioration in recent years.

The Owner will make one generator available for inspection during an off-peak outage before bid opening. At least five days' advance notice will be given to known bidders before the outage.

1.3 SUBMITTAL REQUIREMENTS[5]

1.4 DRAWINGS, DATA, AND REPRESENTATIVE TO BE FURNISHED BY THE CONTRACTOR

1.4.1 Approval Drawings and Data - Within 30 calendar days after date of receipt of notice of award of contract and before proceeding with factory fabrication, the Contractor shall submit to the Contracting Officer, for approval, five sets of all drawings, wiring diagrams, winding installation instructions, and data that are necessary in the opinion of the Contracting Officer for the Owner to determine that the armature windings will conform to the requirements of these specifications. All of the approval drawings shall be submitted promptly. The time required for return of the approval drawings will start with the date of receipt of the last required approval drawings and data. All drawings, data, and letters shall be in English, and dimensions shall be in feet and inches, weights shall be in pounds, and volumes shall be in cubic feet or inches. Where feasible, all outline assembly and detail drawings shall be made to scale. When a scale is used to make a drawing, it shall be an engineer's or architect's scale with its graduations conforming to the United States of America foot and inch system. The drawings and data shall include the following:

(a) Stator coil design including sectional views of stator coils in slot with all dimensions, showing stranding, turn and ground insulation, wedges, fillers, springs, and resistance temperature detectors. Also, a view showing overall dimensions and angles of the coils and defining if the coils are left or right front when viewed from inside the stator bore. A drawing shall also show twist in coil loops, radial angles of slots, diamond legs, loop drop dimensions, support ring locations, tie down procedures, coil end separators, and tie and lock procedures.

(b) Transposition drawing showing method of insulating cross-over points, development of strand cross-overs, start and finish numbering system of strand ends, connecting strands coil to coil, and insulation of connections.

(c) Winding diagram, including an insert showing the parallel paths in each phase and showing views or notes clearly defining a slot-numbering system, a method of determining the slot number in which each coil side is located, and if the coil side is in the top of bottom position. The position of Slot No. 1 within the machine shall also be defined.

In addition, the Contractor shall furnish a tabulation listing each slot, and identifying each phase in the top and bottom position.

(d) Plan and sectional views of parallel rings and connections between coils and parallel rings, and between parallel rings and main and neutral leads.

(e) Description of the insulation and corona suppression systems including a list of materials.

(f) Materials Safety Data Sheets.

(g) Shipping lists of materials furnished.

(h) Drawings showing plan and sectional views of resistance temperature detectors.

(i) Slot location of resistance temperature detectors and confirmation that resistance temperature detectors are located in slots that have the same phase in top and bottom portions of the slot. The Contractor shall also furnish a tabulation listing the slot number and the corresponding coil phase in the slot and location from the neutral or line end of the parallel.

(j) Plan and sectional view details of interchange of main and neutral leads.

(k) Wedge and spring-type wedge filler assembly details.

(l) The Contractor shall submit a sample of the three-conductor cable to be used for wiring the temperature detectors and a 6-inch (15.24 cm) section of the spring-type wedge filler material.

(m) A step-by-step description of the insulation system (materials and application) and a 6-inch (15.24 cm) sample of a slot taken from a completed coil that has an identical taping system to that proposed for these specifications.

Data shall include:

(1) Description and thickness of insulation system for strand, (turn),[6] and ground wall.

(2) Net mica thickness and volts/mil stress on (turn and)[7] ground insulation.

(3) Copper cross-sectional area of strands and circuit rings.

(4) Evidence that the insulation system is Class F, as defined in ANSI C50.10.

(n) A step-by-step description of the installation procedure. The description shall be in narrative form and shall include drawings or sketches, photographs, a list of materials, descriptive literature of resins and tapes, a list and description of tools unique to armature rewind work, and any other information necessary to clarify the description. The description should state specific installation characteristics that will prevent any and all slot materials from moving in the slots or working loose in the future, and describe a method of periodically checking the winding after installation to ensure that it remains securely installed. The description of the installation procedures shall include the following:

(1) Description of coils.

(2) Preparation of stator core to receive the new winding.

(3) Method of checking and adjusting stator core tightness and levelness including clamping bolt tension or torque value.

(4) Adjustment and insulation of surge rings.

(5) Installation of bus rings.

(6) Installation of stator coils, including method of connecting series, pole, and lead connection, and method of insulating the connections.

(7) Description and amount of side packing in slots.

(8) Method of installing spring-type wedge filler and method of measurement of tightness of coils in slots and of amount of spring-type filler compression.

(9) Method of installing and of measurement of tightness of wedges.

(10) Using a 6-inch long by 1/2-inch wide (15.24-cm long by 1.27-cm wide) woven copper strap or other approved method, define the range of ohmic values that confirms an appropriate ground contact is achieved over the entire slot portion of the coil side.

(11) Testing of the completed winding.

(o) Calculations, including formulae, for determining the maximum forces on each coil side in the slots for same phase and for different phase coil sides.

(p) A complete list of spare parts that the Contractor considers to be shelf-life limited or that require a specific storage environment as defined under SPARE PARTS in the bidding schedule.

If revised drawings are submitted for approval, the changes from the previous submittals shall be clearly identified on the drawings, with every revision made during the life of the contract shown by number, date, and subject in a revision block, and a notation shall be in the drawing margin to permit rapid location of the revision. The drawings shall be clear and legible in all respects.

The Contracting Officer shall have the right to require the Contractor to make any changes in the equipment design that may be necessary, in the opinion of the Contracting Officer, to make the equipment conform to the requirements of these specifications, without additional cost to the Owner.

Approval by the Contracting Officer of the Contractor's drawings shall not be held to relieve the Contractor of any part of his responsibility to meet all of the requirements of these specifications or for the correctness of his drawings. Any manufacturing done or shipment made before approval of the drawings will be at the Contractor's risk.

(Drawings shall not exceed 21 inches [53.34 cm] in height or 36 inches [91.44 cm] in width.)

A narrative index list shall be furnished by the Contractor indicating Contractor's drawing number and drawing title, and Owner identifying number. The narrative index list shall be identified by solicitation/specifications numbers and project.

1.4.2 Final Drawings - When the armature winding coils are ready for shipment, the Contractor shall furnish (one) complete set of final drawings (and/or) computer files on 3.5-inch floppy disk or CD-ROM. All revisions shall be indicated in dated and signed or initialed revision blocks. The Contractor shall also furnish sufficient information to facilitate the identification of parts, and eight sets of complete instruction manuals for the operation, maintenance, and repair of the equipment.

1.4.3 Test Reports - Within two weeks after completion of those tests required at the factory on each armature winding and resistance temperature detectors and those tests required on the armature windings during installation, the Contractor shall furnish five certified copies of all test reports and data.

At least two weeks prior to start of the field tests, the Contractor shall furnish five copies of calibration certificates on all test instruments.

Within three months after completion of field tests, the Contractor shall furnish five certified copies of reports of the results of the field tests and shall furnish five copies of curves showing the characteristics of the machines as determined by the tests. Five copies of certificates on all test instruments calibrated after the field tests shall also be furnished.

1.4.4 Design Data - After the design of the generator armature winding has been completed, but in any event within 30 calendar days after receipt of notice of award of contract, the Contractor shall furnish five copies of the following calculated data regarding the generator(s) with the new armature windings:

(a) Losses for rated voltage, power factor and kilovolt ampere output, and 60 Hz, segregated as follows:

(1) Armature I^2R.
(2) Resistance of armature winding at 75°C.[8]

(b) Deviation factor of waveform.

(c) Maximum value of no-load, balanced, telephone-interference factor.

(d) Maximum value of no-load, residual, telephone-interference factor.

(e) Maximum temperature rise in degrees Celsius above 40°C ambient, at rated volts, power factor, and kilovolt amperes for the:

(1) Armature winding by embedded detector.
(2) Field winding by resistance.

(f) Field current required for operation at

(1) Rated volts, rated power factor, and rated kilovolt amperes.[9]
(2) Rated volts, unity power factor, and rated kilovolt amperes.

(g)[10] The method of calculating and the value of test voltage to be used for the dielectric test for multiturn coils a wiring diagram of the test circuit, and a description of the test procedure.

(h) Ampere turns required to establish approximately normal working flux density and proposed method of conducting the stator core iron test, including kilovolt ampere requirements for power supply, and cable.

(i) Total capacitance of one phase of the armature winding to ground.

(j) Calculations including formula for determining the maximum forces on each coil side in the slots for same-phase and for different-phase coil sides.

(k) Nominal dielectric stress in volts per mil of the stator winding insulation.

1.4.5 Additional Design Data for Uprated Generator:[11] Calculated Synchronous Machine Quantities:

(a) Direct-Axis Synchronous Reactance (X_d).

(b) Quadrature-Axis Synchronous Reactance (X_q).

(c) Direct-Axis Transient Reactance (X'_d).

(d) Quadrature-Axis Transient Reactance (X'_q).

(e) Direct-Axis Subtransient Reactance (X''_d).

(f) Quadrature-Axis Subtransient Reactance (X''_q).

(g) Negative-Sequence Reactance (X_2).

(h) Zero-Sequence Reactance (X_0).

(i) Positive-Sequence Resistance (R_1).

(j) Negative-Sequence Resistance (R_2).

(k) Zero-Sequence Resistance (R_0).

(l) Portier leakage reactance (X_1).

(m) Direct-Axis Transient Open-Circuit Time Constant (T'_{do}).

(n) Direct-Axis Transient Short-Circuit Time Constant (T'_d).

(o) Direct-Axis Subtransient Open-Circuit Time Constant (T''_{do}).

(p) Direct-Axis Subtransient Short-Circuit Time Constant (T''_d).

(q) Short Circuit Time Constant (T_a).

(r) Machine Saturation at rated voltage (Sd1.0).

(s) Short-circuit time constant, stator winding.

(t) Initial, rms, symmetrical, three-phase, short-circuit current.

(u) Initial rms, symmetrical, single-phase short-circuit current.

(v) Initial, rms, symmetrical, phase-to-neutral, short-circuit current.

(w) Sustained, rms, three-phase, short circuit current.

(x) Sustained, rms, single-phase, short circuit current.

(y) Sustained, phase-to-neutral, short-circuit current.

(z) Regulation in percent of rated voltage.

(aa) Field current and collector ring voltage required for maximum uprated kilovolt ampere output at rated voltage and power factor.

(bb) Characteristic curves as follows:

(1) No-load saturation.
(2) Full-load saturation, zero power factor leading.
(3) Full-load saturation, unity power factor.
(4) Full-load saturation, rated power factor lagging.
(5) Full-load saturation, zero power factor lagging.
(6) Short-circuit saturation.
(7) Capability curve.

(cc) Short-circuit ratio.

(dd) Maximum line-charging capacity of the generator, neglecting heating, without the generator becoming completely self-excited when operating at normal rated voltage and frequency, when connected to a transmission circuit or circuits, open circuited at the receiving end.

(ee) Overexcited synchronous condensing capacity (zero power factor) when operating at rated frequency and rated voltage and field current for rated output.

(ff) Value of $I_2 2_T$ (integrated product) capability of the generator as defined in Paragraph 6 of ANSI C50.12.

(gg) Damping torque coefficient - D.

(hh) Ventilation report, including computer study of anticipated air flow rates and pressure drops across all parts of the cooling and ventilation system.

(ii) Report detailing analysis and effects the radial flux has on the stator winding heating, especially the top strand heating. The report is to include the following: eddy current losses, graphs showing the effect of over- and undervoltage operation on the hot spot temperature, and the temperatures in the end regions of the core.

(jj) Machine inductances as follows:

(1) Self-inductance of each phase of the stator winding.

(2) Self-inductance of the rotor winding if it is being modified.

(3) Mutual inductance of each phase of the stator winding and of the rotor winding.

(4) Maximum value of mutual inductance between any phase and the rotor winding.

(5) Mutual inductance between two phases of the stator winding.

1.4.6 Contractor's Representative - Within 30 calendar days after date of receipt of all approval drawings and data required above and upon written request of the Contracting Officer, the Contractor shall, at the Contractor's own expense, send a responsible engineering representative from the Contractor's design office to the Owner's office, to review the drawings and the installation procedure with the Owner's engineers for conformance with the requirements and intent of these specifications. The Contractor's representative shall be fully informed of the intent of the Contractor with respect to manufacturer and installation and shall follow progress in the design office, the shop, and at the site. The Contracting Officer will notify the Contractor at least 10 calendar days in advance of the date set for review with the Contractor's representative.

The intent of the foregoing requirements is to avoid delay in completion of the contract that might be caused by a misunderstanding of the requirements of these specifications and especially the installation procedure.

1.4.7 Mailing of Drawings and Data - All drawings and data specified above shall be forwarded by the Contractor to: _____.

DIVISION 2 - MATERIALS AND WORKMANSHIP

Note: This section correlates with other sections of the specifications and may not be complete in itself.

2.1 MATERIALS AND WORKMANSHIP

Unless otherwise stated in these specifications, materials used in the manufacture of the equipment shall be new and of the highest standard commercial quality as normally used for this type of equipment, and free of defects, considering strength, ductility, durability, best engineering practice, and the purpose for which the equipment is to be used.

Liberal factors of safety, which will ensure durability and reasonably to be expected life for all new components, shall be used throughout the design and especially in the design of all parts subject to cyclic stress or shock. For all new parts of the equipment, the maximum stress in the materials shall not exceed one-third of the yield strength nor one-fourth of the ultimate tensile strength then subjected to maximum normal operating conditions (including load rejection or short circuit at the machine terminals).

2.2 WORK AND MATERIALS TO BE FURNISHED BY THE OWNER

2.2.1 The Owner will furnish, without cost to the Contractor, the following labor, materials, and storage, and perform the following work:

(a) Disassemble the generator, including removing the exciter, generator rotor and shaft, and such other parts required to make the stator readily accessible to the Contractor.

(b) Reassemble the generator (including installation of winding, ring buses, and blocking) (only if the owner will perform the installation) after installation, dry out, and dielectric test of the new armature winding by the Contractor.

(c) Furnish the cranes and crane operator required for removal and installation of the windings.

Scheduling and use of the cranes by the Contractor shall be subject to approval by the Contracting Officer, who will coordinate use of the cranes by the Owner and by the Contractor. Any labor, other than the crane operator, required to handle the equipment, materials, or supplies shall be furnished by the Contractor.

(d) Furnish alternating-current electrical energy at _____ volts, _____ phase as required by the Contractor in connection with the installation of the generator armature winding and field testing of the generator.

(e) Furnish alternating-current electrical energy at _____ volts, _____ phase as required by the Contractor in connection with drying out or curing the new armature winding.

(f) Furnish (cables and) alternating-current electrical energy of suitable voltage required by the Contractor for the stator core iron test.

(g) Furnish such scaffolding and work platforms as it has available, but in no way guarantee their adequacy.

(h) Provide the use of the hydraulic turbine and such facilities as the Owner has available for preliminary operation of the generator and for making field acceptance tests on the generator.

(i) Furnish both direct- and alternating-current, high-potential test sets for applying high potential to the winding during the dielectric tests. The Owner will furnish the labor to set the high -potential test sets in position and to make them ready for operation.

The test sets will have the following ratings:

Alternating current - _____

Direct current - _____

Any other high-potential test equipment required shall be furnished by the Contractor.

(j) Furnish the required instruments and conduct direct-current absorption tests.

(k) Furnish water and compressed air - Compressed air at approximately _____ pounds per square inch (psi) (_____ megapascals [MPa]) and water can be furnished from service outlets. The Contractor shall furnish and install, at the Contractor's own expense, any additional pipelines, connections, and appurtenances required by the Contractor for the Contractor's own use or convenience in performing the work. The Contractor shall remove all such additional pipelines, connections, and appurtenances upon completion of the work. No waste of Owner-furnished water and air will be permitted.

(l) In the event storage is required for any generator materials prior to their installation, such storage shall be at the risk of and at the expense of the Contractor. The Owner will, however, cooperate in providing without charge to the Contractor such inside or outside temporary project storage space as might be available for such purpose.

2.3 WORK AND MATERIALS TO BE FURNISHED BY THE CONTRACTOR[12]

2.3.1 Except as otherwise provided in the previous paragraphs, the Contractor shall furnish all labor, materials, equipment, instruments, and tools required in connection with the manufacturer, installation, and testing of the generator armature winding. (The Contractor shall also furnish all labor for removal of the existing armature winding[s] from the job site, including cleanup and transportation.) Labor for testing shall include all labor except that furnished for the acceptance tests and accelerated life tests. Accordingly, labor for testing shall include all major wiring connections involving the generator terminals, generator bus structure, disconnect switches, and all wiring changes involved in the main field and excitation circuit. The Contractor shall be responsible for all transportation and housing costs and subsistence expenses of the Contractor's personnel.

(a) The Contractor shall be responsible for all transportation and housing costs and subsistence expenses of their personnel.

(b) The Contractor shall bear all costs of loading, transporting, unloading, and handling all required materials from the Contractor's shipping point or points to the point of storage at the powerhouse. The Contractor shall also bear all costs of transporting test instruments and equipment to and from the job site.

(c) The Contractor shall be responsible for all materials requiring special storage conditions, including controlling temperature, humidity, dust, or any other atmospheric conditions that are not a normal condition at the powerplant.

(d) Furnish scaffolding and work platforms as required.

(e) Furnish fire protection for work area.

(f) Furnish personnel safety equipment, such as hard hats, safety glasses, hearing protection, respirators, and first aid supplies.

(g) Dryout of the stator winding, if necessary, will be accomplished by the Contractor.

(h) Furnish wire ropes and slings for removal and installation of new stator windings as necessary.

(i) Provide local (in the immediate work areas) approved flammable liquid storage cabinets to be used for the storage of solvents, resins, and other flammable liquids.

(j) Conduct a safety inspection after each final shift for fire hazards, unnecessary energized equipment, and materials and boxes, that may block access.

(k) Each shift shall check in and out of the control room upon their arrival/departure to/from the project.

(l) No exhaust emissions will be allowed inside the powerhouse, which may be generator by gas or diesel driven winding sets.

(m) The Contractor shall provide an On-Site Technical Supervisor who shall provide technical direction to the installation crews. This shall include but not be limited to training of special procedures that may be required to install the core and winding, inspection of the work to ensure that the drawings and installation procedures are being followed, and quality assurance of the work, progress reports, general planning, and layout of the work performance evaluation of the installation crews, and training of necessary safety procedures. The Site Technical Supervisor shall be present at the site at all times when work is in progress or must be available within four hours of the Owner's request. The Owner shall have

the right to require the Contractor to replace any Site Technical Supervisor who fails to comply with Contract Document requirements.

(n) The Contractor will be paid under the provisions of the clause in entitled "Extras" for any repairs the Contractor performs on the stator core iron or other generator components that are ordered by the Contracting Officer and that are not required because of an act of the Contractor.

(o) The Contractor shall bear all cost of transporting all generator winding materials, from the Contractor's shipping point or points to the point of storage at the job site; and from the point of storage to within reach of the powerplant cranes. The Contractor shall also bear all costs of transporting test instruments and equipment to and from the job site.

(p) The Contractor shall be responsible for all materials requiring special storage conditions, including controlling temperature, humidity, dust, or any other atmospheric conditions that are not a normal condition at the powerplant. The Contractor shall advise the Owner of all materials that have a limited shelf life and that the Contractor recommends to be shipped immediately prior to installation. All hazardous materials shall be plainly identified as such on the container along with a label stating the contents, handling, and first-aid treatment. The Contractor shall also provide a storage cabinet or other suitable facilities for storing flammable or toxic materials.

(q) (The Contractor shall furnish the cables and other material required for the stator core iron test. The length of cable shall be sufficient to equally space the turns around the entire stator core. After completion of the core tests, the cable and materials shall become the property of the Owner [if interlaminar core {loop} tests are required.])

(r) Infrared, temperature-detection devices shall be furnished by the Contractor for determination of core temperatures and location of hotspots during core testing.

2.4 REFERENCE SPECIFICATIONS AND STANDARDS

2.4.1 The standards applicable to the work include:

ANSI C42.100	Dictionary of Electrical and Electronic Terms.
ANSI C50.10	General Requirement for Synchronous Machines – "Rotating Electrical Machinery - Synchronous Machines."
ANSI C50.12	Requirements for Salient Pole Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications.
ANSI C50.13	Requirements for Cylindrical-Rotor Synchronous Generators.[13]

ANSI/IEEE STD 1	General Principles for Temperature Limits in the Rating of Electric Equipment and the Evaluation of Electrical Insulation.
ANSI/IEEE STD 4	IEEE Standard Techniques for High Voltage Testing.
ANSI/IEEE STD 43	IEEE Recommended Practice for Testing Insulation Resistance of Rotating Machinery.
ANSI/NEMA MG1	Motors and Generators.
ASTM D1868	Detection and Measurement of Partial Discharge (Corona) Pulses in Evaluation of Insulation Systems.
CSA C22.1	Canadian Electrical Code Part I - Safety Standards for Electrical Installation.[14]
CSA C22.2	Canadian Electrical Code Part II - Safety Standards for Electrical Equipment.[15]
CSA - CAN 3	Z299.3 Quality Assurance Program - Category 3, or ISO 9001.[16]
IEEE STD 43	Recommended Practice for Testing Insulation Resistance of Rotating Machinery.
IEEE STD 95	Guide for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage.
IEEE STD 115	Test Procedures for Synchronous Machines.
IEEE STD 119	Recommended Practice for General Principles for Temperature Measurement as Applied to Electrical Apparatus.
IEEE STD 286	Recommended Practice for Measurement of Power Factor Tip-Up of Rotating Machinery Stator Coil Insulation.
IEEE STD 393	Standard Test Procedures for Magnetic Cores.
IEEE STD 492	IEEE Guide for Operation and Maintenance of Hydro-Generators.
IEEE STD 1043	Recommended Practice for Voltage-Endurance Testing of Form-Wound Bars and Coils.
IEEE STD 522	Testing Turn-to-Turn on Form Wound Stator Coils for AC Rotating Electric Machine.

DIVISION 3 - GENERATOR ARMATURE WINDING

Note - This section correlates with other sections of the specifications and may not be complete in itself.

(The following specifications written in singular form for one winding shall apply equally to all windings except where specifically stated otherwise.)

3.1 TYPE AND RATING

3.1.1 General - The generator armature winding shall be for replacing the winding in an existing generator unit. The existing generator is rated as indicated above. After installation, the new generator armature shall conform to the latest American National Standards, except as otherwise specified herein. The new armature winding shall be rated for operation continuously as indicated below.

The stator core has an inside diameter of _____ inches (_____ mm), an outside diameter of _____ inches (_____ mm), and is a nominal _____ inches (_____ mm) high.

3.1.2 Rating

Kilovolt amperes ..... _____
Power factor ..... _____
Frequency..... 60 Hz
Number of phases.....3
Voltage between phases, volts ..... _____
Speed, r/min ..... _____
Armature winding.....Wye connected, suitable for either grounded or ungrounded neutral operation

3.1.3 Generator Data - Information concerning the existing stator and the armature winding slots is approximately as indicated on the drawings. The Owner assumes no responsibility for the uniformity of the existing stator or for the accuracy of the dimensions given. The Owner, upon request, will make an assembled generator available for inspection by any offeror, providing sufficient notice is given to arrange for the generator outage. Also, any offeror will be permitted to inspect operating data, test data, generator drawings, and any other material that the Owner has available at the job site. Inspection schedules shall be coordinated with the Contracting Officer _____, telephone _____.

The kilowatt losses, resistance values, and test data listed in the following Informational Data Table are for the offeror's information and are the result of tests conducted on an existing similar generator.

Informational Data Table

(a) Kilowatt losses and resistance values:

Kilowatt Losses

	Load of (at _____ kV and _____ power factor)				
	kV·A 115% rated	kV·A 100% rated	kV·A 75% rated	kV·A 50% rated	kV·A 25% rated
Friction and windage	_____	_____	_____	_____	_____
Core loss	_____	_____	_____	_____	_____
Stray-load loss	_____	_____	_____	_____	_____
Armature I^2R loss (75°C)	_____	_____	_____	_____	_____
Rotor I^2R loss (75°C)	_____	_____	_____	_____	_____
TOTAL LOSSES	_____	_____	_____	_____	_____

Resistance Values

Armature resistance (line to neutral) ..... at 75°C is _____ ohm(s)
Rotor resistance (at collector rings) ..... at 75°C is _____ ohm(s)

Information Data Table Continued

(b) Test data:
No-load, balanced, telephone-interference factor = _____
No-load, residual, telephone-interference factor = _____
Deviation factor of waveform = _____ maximum (L-N) and _____ maximum (L-L)
Heat run data for the offeror's information are the result of tests performed on an existing similar generator and at the loading conditions stated:

	Heat Run Number 1	Heat Run Number 2
Kilovolt amperes		
Voltage		
Armature current		
Power factor		
Field voltage		
Field current		
Ambient temperature °C		
Total armature temperature °C		
Armature temperature rise °C		
Total field temperature °C		
Field temperature rise °C		

3.2 TEMPERATURE RISE

The maximum temperature rise of the new stator winding shall not exceed 80°C[17] when the generator is delivering rated load and with cooling air entering the generator at not more than 40°C. The temperature of the armature winding shall be determined by means of embedded resistance-type temperature detectors located in the armature winding. The temperature of the cooling air entering the generator shall be the ambient temperature.

The field current requirement at rated load shall not be greater than that required for the existing winding.

3.3 ELECTRICAL CHARACTERISTICS[18]

3.3.1 The electrical characteristics of the generator after installation of the new armature winding shall be as follows:

(a) The no-load, balanced, telephone-interference factor shall not exceed 70.

(b) The no-load, residual, telephone-interference factor shall not exceed 50.

(c) The wave-form deviation factor shall not exceed 10%. Special attention is directed to the necessity of eliminating from the voltage waves the harmonics that

may cause inductive interference with communication circuits or resonance in the transmission system.

3.4 STRUCTURAL DETAILS

3.4.1 The armature winding will be installed in a generator having clockwise rotation when looking down on the unit. The armature winding, insofar as it is practicable, shall be designed so as not to require modification of any part of the existing generator or associated equipment. Any modification of the existing generator or associated equipment because of the new armature winding shall be subject to approval by the Contractor Officer and shall be done by and at the expense of the Contractor. Modifications shall be limited to conditions affecting the armature coils, end connections, circuit ring buses, or main lead. Any defects found in the existing generator, as determined by the Contracting Officer, will be corrected at the expense of the Owner. All parts of the armature winding, after installation, shall be capable of withstanding the short-circuit requirements of ANSI C50.12.

3.5 ARMATURE WINDING

3.5.1 General - The armature winding shall be for wye connection with the main leads and neutral leads brought out of the stator frame. (The arrangement of the leads shall be such that the main leads and the neutral leads can be readily interchanged, by changing connections between the circuit ring buses and the main and neutral leads. The Contractor shall furnish the necessary materials to accomplish this interchange.)[19] The short-circuiting bar on the wye connection of the current transformers shall (be replaced and)[20] remain uninsulated. The armature winding shall be protected by (existing)[21] differentially connected current transformers and relays (including split-phase differential relaying) for protection against ground and short circuits.

The Contractor shall furnish all blocking and lashing material, tape, supports, binding materials, new surge ring[22] and surge ring insulating materials, slot fillers, slot corona treatment materials, and all other materials necessary for complete installation of the new armature winding in the stator. Spacers used in bracing the end turns at the top and bottom portions of the coils and surge rings shall be of either phenolic laminate or polyester glass laminate, and shall be covered with a material such as dacron felt. The material shall be thoroughly impregnated with a solventless epoxy or polyester resin of high insulation properties prior to its installation. Glass cord or tape shall be used to tie the blocking material and coils, and the cord or tape shall be saturated with a solventless epoxy or polyester resin prior to tying. A locking device or “figure 8” tie shall be used at the bottom of the slot to prevent slot materials from sliding downwards. The locking device or tie shall be located approximately 0.5-inch (12.7 mm) below the stator iron to allow limited migration of any loose slot materials as an aid to visual inspection for such migration. Blocks on the sides of coils, or other positive means, shall be provided to prevent downward movement of the coils. If blocks are used, they shall be tied to a straight portion of the coil at the point of exit of the coil from the top of the core.

There shall be sufficient space between coils in the end turn area[23] and between jumpers[24] to prevent electrical discharge or corona between coils.

3.5.2 Insulation - All materials used in the manufacture and installation of the new stator winding shall be compatible with each other and be rated ANSI Class F[25] or better. The bonding resins shall have properties, characteristics, and chemical effects associated with operation within the temperature limits of the insulation system.

Each strand shall be individually insulated. The strand insulation shall be glass, dacron glass, or mica tape. The strands shall be tightly pressed and bonded together before the ground wall insulation is applied. The turn insulation shall consist of mica tape and shall be completely impregnated or filled with a solventless epoxy or polyester resin.

The ground insulation shall be tape consisting of mica splittings or mica paper, and the necessary backing, binding, and filling materials. The same taping system and materials shall be used throughout the ground insulation of all power-carrying conductors, including coil interconnections. Mica splittings, if used, shall meet the requirements for National Electrical Manufacturers Association (NEMA) Grade C classification as given in NEMA Standard for Manufactured Electrical Mica (ME 1 1965).

The ground insulation shall be completely impregnated or filled with a solventless epoxy or polyester resin using either the vacuum-pressure-impregnation process, or by means of a "B-staged" epoxy or polyester-impregnated tape.[26] Regardless of the system used for impregnation, the insulation shall be a solid, dense structure with minimal voids or air pockets. The coils external surfaces, including the bend areas shall be smooth and free from wrinkles and surface irregularities. The coils shall be capable of being placed into position in the slots without damage to the insulation. The coils shall be treated so as to prevent permanent injury from temporary exposure to dampness. Use of solvent-type varnish as a tape binder on the circuit rings, main and neutral leads, and coil interconnections will not be permitted.[27]

After the turn and/or ground wall insulation systems have cured, the overall coil insulation system shall not be disturbed other than replacing the protective covering (binder or armor tape).

Preinsulated jumpers will not be permitted in making up series or group connections.[28] Tapes using a polyester film (Mylar) backing will not be permitted in the insulation system.

The coils shall be provided with a protective covering and arranged or treated to reduce corona to the lowest practicable minimum. The slot portion shall be treated with a semiconducting compound to provide corona shielding. The corona shielding shall extend beyond the core and shall be graded outside each end of the core. The coils shall be constructed utilizing one of the following acceptable methods:[29]

(a) Impregnated conductive tape is applied to cover the slot portion of the ground wall insulation and then cured. Conductive room temperature vulcanizing (CRTV) silicone rubber and room temperature vulcanizing (RTV) silicone rubber are press-molded on each side of the bar/slot portion in longitudinal bands and then cured. The RTV/CRTV bands shall allow a zero clearance bar/slot interface on both sides of the bar.

(b) Conductive paint having acceptable and proven abrasion resistance is applied to the slot portion of the ground wall insulation and then cured. Conductive paper is folded with conductive epoxy paste, inserted between folds, and then wrapped around three/four (3/4) sides of the coil slot portion of the coil. The conductive paper thickness or the number of folds will be increased to allow a zero (0) clearance bar/slot interface on both sides of the bar.

(c) Impregnated conductive tape is applied to cover the slot portion of the ground wall insulation through the use of "B-stage" treatments. The coils shall then have a zero (0) clearance bar/slot interface on both sides of the bar.

3.5.3 Coils - The stator coils shall be (single turn Roebel type) or (multiple turn)[30] type coils. The individual strands shall be annealed copper, free from splinters, flaws, or rough spots and shall have a minimum nominal corner radius of 0.024 inches (0.610 mm). The coils shall be manufactured in such a manner that there is a minimum even spacing between end turns, after installation of 0.4 inches (10.16 mm).[31] The finished cell portion of each coil shall be within plus or minus 0.015 inches (0.381 mm) wide and 0.020 inches (0.508 mm) high of the design dimensions. The coil edges shall be pressed to a minimum radius of 1/32 inch (0.79 mm) and a maximum radius of 3/16 inch (4.76 mm).[32] At rated generator voltage, the dielectric stress from the conductor to ground (groundwall plus turn insulation) shall not exceed 60 volts per mil.[33]

The coils shall be capable of being placed in the stator core slots without damage to the armor tape, semi-conducting system, or insulation system. Coils shall be interchangeable. The total cross-sectional area of the copper conductors shall not be less than the cross-sectional area of the existing conductors. Each coil shall be separately numbered. The grading system shall be so constructed that no corona discharges shall exist between any two bars outside the core to cause the surface degradation at any normal operating voltages. As a minimum, the length of the conducting surface on the coil shall be long enough to ensure a separation of at least 1/4 inch (6.35 mm) at the point where the high resistance treatment begins, even when allowing for manufacturing variations. The grading system shall have been laboratory tested and proven at a voltage that is 2 kV higher than the maximum voltage between any two coils in a slot.

(a) Form-wound coils shall be of the same size and shape and shall be interchangeable.[34]

(b) Bar-type coils shall have strands completely transposed (minimum 360°) by the slot portion by the Roebel method with both ends of the coil brought out and extended to connectors. Each two half coils comprising a single coil shall be brazed together in the field before application of the end turn insulation. The end turn insulation shall then be applied as a solid, homogeneous material. Means shall be used to ensure that minimal voids or air pockets occur in the material. Caps used for insulation of connections should be completely filled with thermosetting polyester or epoxy compounds. The construction shall be such as to reduce corona at the connection to a minimum.

In order to ensure mechanical strength and to reduce the probability of hotspots, connections between coils and circuit rings shall include all strands in a common connection. Before application of the ground insulation, the slot portions of the coils shall be impregnated and encapsulated with an epoxy or polyester resin bonding compound to fill and bond the transposed conductors to form a solid void-free structure.

Multiple-turn coils shall have at least one internal coil transposition in the coil shoulders or be transposed by an alternative method to reduce the losses (stray load) due to non-uniform current distribution to a low value. Alternative methods of transposition must have the approval of the Contracting Officer.] Each turn shall be insulated with a minimum of two layers of half-lapped mica tape applied under constant tension.

The Contractor shall be responsible for all the dimensions of the coils and other materials furnished under this contract being correct and satisfactory for installation in the generator. Measurements shall be made on the generator as necessary to ensure this requirement is met and to verify any data listed in these specifications.

3.5.4 Wedges - Provisions shall be made for tightly wedging the coils in the slots with wedges that will not shrink or buckle. Wedges shall be made from glass mat base laminate NEMA Grade G-10 or G-11.[35] All materials in the stator slot shall have Class "F" rating.[36] The wedges at the ends of the slot shall be of the locking type but no adhesive shall be used.[37] As an alternative to the single-piece wedge, the Contractor will be permitted to furnish and install two-part, radial-pressure-type wedges, provided that wedges are constructed with a positive means of measuring the amount of spring compression.

At least one wedge in every 24 inches (60.96 cm) of slot length, with appropriately located gauging holes,[38] shall be installed in each slot to provide a positive means of measuring the actual amount of spring compression.

3.5.5 Slot Fillers - Slot filler strips and slot side fillers shall be fabricated from semiconducting material, except the front filler strip may be constructed of non-conducting material.[39] All materials in the stator slot shall have Class "F" rating. Flat filler strips of semiconducting material shall be installed at the bottom of the slot and between the top coil in each slot and the spring-type wedge filler material.[40]

Side filler strips shall be tight within the slot so that a 0.002-inch (0.051-mm) feeler gauge will not enter any gap between the coil and slot sides. The 0.002-inch (0.051-mm) feeler gauge "no-go" standard shall apply to at least 90% of the stacked core length provided the remaining 10% has "go" lengths of less than three inches (76.20 mm). For at least 90% of the machine, only one thickness of side filler shall be used, and on the remaining 10% only two thicknesses glued together shall be used.

Spring-type wedge filler materials or other Contracting Officer-approved spring system shall be furnished and installed directly behind the wedges for providing a positive radial force on the coils. The spring compression shall be at least 150% of the maximum radial electromagnetic forces produced on the coils. Additionally, the amount of spring compression shall be at least 150% of the total amount of radial decrease of materials in the slot due to shrinkage or relaxation for the expected life of the armature winding.[41] The spring-type wedge filler material may be constructed of nonconducting material.

The Contractor shall furnish all gauges and any other equipment required to determine the total spring compression and shall furnish instruction for using the gauges during installation and during future maintenance inspections. Care shall be exercised that blocking of the air passages does not occur.

3.5.6 Circuit Ring Buses - The winding shall be furnished complete with new circuit ring buses (of sufficient cross section to prevent undue heating at rated generator load, however, the current density in the new circuit ring buses shall not be greater than the current density in the existing buses) (of the continuous type with conductors of flat, solid annealed copper bar with rounded edges) (of solid copper bar with brazed joints).[42] The circuit ring current density shall not exceed 1500 amps psi at rated generator load. The circuit rings shall be fully insulated for 15 kV with full Class "F" insulation or better.[43] Insulation

shall be applied to the circuit rings after the rings have been formed to the necessary radius of curvature. The circuit ring buses shall be provided with new supports and support-mounting brackets to effectively and rigidly support the circuit ring buses under all conditions of normal operation and during short circuits. All materials included in the new supporting structures shall have structural and dielectric strength equal to or better than those materials used on the existing generator. The minimum clearance between the surface of the insulated bus and ground potential shall be 0.75 inches (19.05 mm).[44]

3.5.7 Dummy Stator Core:[45] A partial model of the stator core shall be manufactured from aluminum prior to manufacturing of the prototype coils. The model shall be rigid and shall have sufficient slots to measure a full coil pitch plus one slot and shall include the coil support tie down rings. Rings shall duplicate the sizes and locations of the existing rings. Two of the slots in the core model shall have full slot depth metal running true and straight through the length of the core model. The dimensions of these two slots shall be the same as the slots in the actual unit. The model shall be rigid enough to be used to demonstrate that the prototype and production coils for that unit are able to be side-packed tightly with the specified side fillers and wedges. The aluminum dummy stator core model shall be delivered to the pumping plant after completion of factory testing.

3.6 INDICATING AND PROTECTIVE DEVICES

A minimum of 24[46] standard 10-ohm-copper,[47] 3-conductor, resistance temperature detectors, with at least one per parallel circuit per phase, shall be provided in the armature winding, located so as to indicate, as closely as possible, the highest temperature obtained in operation.

The sensing element shall be encapsulated in a flexible heat-cured compound throughout the entire slot portion and for a short distance past the end of the slot. [48] The leads shall be encapsulated in the same material or protected with acrylic resin-coated fiberglass sleeving.[49]

The necessary wiring between the existing terminal board and the individual temperature detectors shall be provided and installed. The wiring shall comprise a three-conductor cable that is oil, moisture, and heat resistant. The cable shall have armor protection against mechanical damage. The conductors shall be stranded, tinned, copper with an insulation system capable of operating at a temperature of at least 125°C. The cable shall be General Electric specification No. LW 3828, or equivalent.

3.7 WINDING REPLACEMENT

3.7.1 Circulating Current Test[50] - After the rotor has been removed and prior to removal of the existing armature windings, the Owner may at its option perform, with the Contractor's participation, a circulating armature current test to aid in the evaluation of core heating, core looseness and vibration, and turn problems, and any other unusual condition that might occur with balanced, three-phase current flow in the armature winding, but that might not be detected during the ring test. This test consists of supplying armature current from an adjacent unit through the existing buswork to raise the temperature of the test unit to 120°C using the existing resistance temperature detectors to monitor the temperature. Armature current will be increased slowly as temperatures exceed 100°C to avoid overheating.

The Owner will record complete data considered to be useful in evaluating the operation of the unit.

A similar test may be made on each new armature winding installed, provided a satisfactory test procedure can be developed and is mutually agreeable to the Contractor and the Owner, and further provided that a supply generator can be made available to perform the test. The test might be beneficial for checking the installation in general, and specifically all brazed joints, and would aid the curing process of the new field-insulated connections.

3.7.2[51] Removal of Existing Stator Winding[52] - The Owner shall remove the existing stator winding under the direction of the Contractor's engineer. The winding manufacturer shall maintain an erection engineer on site to provide technical supervision of work performed to remove the existing stator windings, including all coils, end connections, the ring bus, and other components as necessary for installation of the new stator core and windings furnished under this contract. The manufacturer shall provide a detailed, written procedure for work to be performed to remove the existing stator winding, including the requirements such as that such removal does not contaminate the surrounding area with dust, and that salvaged materials are delivered to a storage site designated by the Owner outside of the powerhouse.

3.7.3[53] Removal of the Existing Stator Winding - The Contractor shall remove the old armature winding including all coils and connections and that portion of the ring bus, if any, not being reused, in a manner that will not damage the stator core or other parts of the generator not being replaced. The Contractor will be responsible for any damage caused in removal of the old winding.

All materials removed will remain the property of the Owner and shall be delivered to the Owner at the site of the work. Materials removed shall not be reused in the generator unless authorized by the Contracting Officer.

All materials removed will become the property of the Contractor. All discarded and salvaged materials shall be removed promptly and disposed of according to applicable regulations.

3.7.4 Testing and Repair of Armature Core Iron - Interlaminar test shall be conducted as described in the testing section of the specifications. Repair shall be performed as required below.

3.7.5 Repair - For any repair work required, other than cleaning and treating the armature winding slots, the Contractor shall furnish materials required and perform the work, for which he will be reimbursed for services and materials,[54] (except for existing spare stator laminations) in accordance with the clause entitled "Extras." The Contractor shall also be entitled to an extension in completion time for performing this work, as described in the clause entitled "Time of Installation." The Contractor shall be responsible for the adequacy of the repairs. The method will be subject to approval by the Contracting Officer.

3.7.6 Installation of Armature Winding - The Contractor shall install and connect the new armature winding complete throughout, shall connect the armature winding main leads to the generator voltage bus structure, and shall connect the armature winding for normal operation. Prior to installing the new armature winding, the Contractor shall, at his own expense, clean and paint the armature winding slots with a semiconducting compound to provide corona shielding. Application of the compound by compressed air methods will not be permitted. If necessary, the Contractor shall reestablish the wedge-locking notch.

Connections throughout the armature winding, except for bolted connections at the main and neutral leads, shall be brazed. Connections shall be brazed using a brazing filler metal having a melting temperature above 80°F (427°C), meeting the requirements of the latest edition of the American Welding Society Standards A2.0 and A5.8. The brazing procedure shall be such as to ensure complete and thorough distribution of the brazing filler metal throughout the joint of the connection. The coil interconnections shall be insulated with mica tape and impregnated with the solventless epoxy or polyester resin. No permanent bends shall be made in any part of the winding after insulation has been applied to that part. All work shall be performed under the technical direction of an erection engineer to be furnished by the Contractor. The installation procedures shall be submitted by the Contractor within 30 days after award of contract and shall be approved by the Contracting Officer before the work is performed.

The Contractor shall install at least one resistance temperature detector (RTD) in each parallel circuit of each phase and in a slot with the same phase in front and back of the slot.

The Contractor shall furnish and use new slot wedges, front and side slot fillers, blocking, and lashing material.

The Contractor shall reinsulate the (top and bottom) surge rings with new insulating material. (The Contractor shall furnish and install new top and bottom surge rings that are adequately insulated.)

The Contractor shall accurately measure and record each slot before and after the application of the semiconducting compound in the slots and provide suitable wedges and fillers to provide uniform tightness of the installed armature winding coils. To check the adequacy of grounding of the coils in the slot, the Contractor shall measure and record the resistance between each coil side (top and bottom) and ground. The measurement method shall include the use of a 6-inch by 1/2-inch-wide (15.24-cm by 1.27-cm wide) woven copper strap or approved alternative, and the maximum allowable resistance shall be determined by the Contractor and shall be subject to the approval of the Contracting Officer. During and after installation of the new armature winding, but prior to reassembly of the generator, the Contractor shall dry out or cure the windings as necessary and conduct dielectric tests. After the installation is complete, the Contractor shall paint the exposed portion of the core and the wedges, the exposed portion of the coils above and below the core, series and pole jumpers, leads to the circuit ring buses, and the circuit ring buses with Buff Epoxy Enamel - Glyptal No. 74004 Insulating Varnish combined with General Electric No. 74010 catalyst,[55] or an equivalent insulating system. The total applied dry thickness shall be 5 to 15 mils.

3.7.7 Asbestos Removal - The existing windings (ring buses, and main and neutral leads) (may) (are known to) contain asbestos material. The Contractor shall remove and dispose of these components in a method that complies with all regulations. The Contractor shall provide a detailed, written procedure for handling of the asbestos material including the following requirements:

(a) Warning that exposure to airborne asbestos has been associated with four diseases: Lung Cancer, certain Gastro-Intestinal Cancers, Pleural or Peritoneal Mesothelioma, and Asbestosis. Studies indicate there are significantly increased health dangers to persons exposed to asbestos who smoke and, further, to family members and other persons who become indirectly exposed as a result of the exposed worker bringing asbestos-laden work clothing home to be laundered.

(b) Friable and/or nonfriable asbestos-containing material shall be removed that has been identified in the generator units in the (winding) (main and neutral lead areas and on group and circuit jumpers).

(c) Asbestos Control: At least 30 days before commencing any disassembly of the generator unit, the following information relating to asbestos monitoring, control, and removal shall be submitted for review and approval by the Owner:

(1) Identification of the certified industrial hygienist who will be performing asbestos monitoring. The identification shall include the certification number of the industrial hygienist.

(2) Identification of the American Industrial Hygiene Association (AIHA) accredited laboratory that will be analyzing air and material samples taken at the powerhouse work area.

(3) A written procedure for the monitoring, removal, and disposal of asbestos materials. The procedures shall meet all of the requirements of the latest applicable Washington Industrial Safety and Health Act (WISHA) and Occupational Safety and Health Administration (OSHA) regulations.

3.7.8 Lead Paint Removal - Coatings in areas where scraping, cutting, grinding, or welding will occur very likely contain lead either in the primer or in the opt coat(s). The Contractor shall verify the actual presence of lead in the work area. The Contractor shall comply with all federal and state regulations applicable to lead removal and shall also ensure that lead-contaminated debris is not released into the environment or into the plant. As a minimum, the Contractor shall make the following submittals:

(a) Method(s) to be used to remove existing coating and to collect debris.

(b) Description of proposed containment method(s), including the ventilation plan (if applicable), and methods that will be used to ensure that lead contaminants do not enter the environment or the plant.

(c) Worker protection plan, per 29 CFR 1926 and 29 CFR 1920.1025. Submittals are to include, at a minimum, programs for air sampling, medical surveillance, respiratory protection, personal hygiene, OSHA personal monitoring, and employee training (40 CFR 265.16).

(d) Programs for compliance with the Clean Air Act (40 CFR 50, 40 CFR 60, Steel Structures Paining Council [SSPC] Guide 6I, 29 CFR 1910.94).

(e) Program for compliance with solid and hazardous waste regulations, SSPC Guide 7I.

(f) Plan for analyzing, handling, and disposing of waste. Include sampling methods, documentation for how, when, where samples will be taken, container labeling requirements, lab that will be performing the Toxic Characteristic Leaching Procedure (TCLP) tests, and chain of custody forms.

The Contractor shall be responsible for obtaining samples and having TCLP tests performed on the waste material to determine whether it is classified as hazardous.[56] A minimum of four random samples shall be taken and tested. Should more than four drums of waste be accumulated, then one sample shall be taken and tested from each drum. The Owner (Contractor) shall be responsible for providing Department of Transportation (DOT) approved waste drums for disposal of hazardous waste and shall also be responsible for disposal of hazardous waste. The Contractor shall be responsible for containerizing of all waste.

DIVISION 4 - PACKAGING AND MARKING

Note - This section correlates with other sections of the specifications and may not be complete in itself.

4.1 PREPARATION FOR SHIPPING AND HANDLING

4.1.1 The Contractor shall prepare all materials and articles for shipment in such manner as to protect them from damage, and in addition shall be responsible for and make good any and all damage due to improper preparation or loading for shipment. Heavy or bulky parts or equipment shall be provided with eyebolts, lugs, or other lifting devices to facilitate handling with a crane and, if necessary, shall be mounted on skids or crated. Where parts are boxed or crated and it is unsafe to attach slings to the box or crate, slings shall be attached to the parts, and the slings shall project through the box or crate so that attachment can be readily made. Instructions for handling and lifting all parts, boxes, and crates shall be clearly painted on or attached to the part or crate. Any articles or materials that otherwise might be lost shall be boxed or bundled and plainly marked for identification. All finished ferrous surfaces shall be coated with a rust-preventive compound, and all finished nonferrous metalwork and devices subject to damage shall be suitably wrapped or otherwise protected from damage during shipment. Each container shall have its contents clearly identified for proper warehousing. A complete packing list shall be transmitted to the job site 30 days before shipment and a copy must accompany each shipment.

The spare parts shall be packed in moisturetight containers or covered with moisturetight wrappings and otherwise shall be prepared for extended storage at the powerplant. Proper precautions shall be taken with all sensitive devices to prevent damage during shipment.

All hazardous materials shipped to the site shall be plainly identified as such on the containers along with a label stating the contents, handling, and first-aid treatment.

All winding material is to be packed for long-term storage. The Contractor shall prepare, pack, and load all materials and equipment for shipment completely protected from damage and shall be responsible for any damage resulting from improper packing. Items subject to open storage for several months at the job site shall be suitably protected from soil and weather. Articles or materials that might otherwise be lost shall be boxed or steel banded in bundles and plainly marked for identification. All parts exceeding 200 pounds (90.72 kg) gross shall be prepared for handling by crane with suitably and readily attached slings while on the transport.

DIVISION 5 - INSPECTION AND ACCEPTANCE

Note - This section correlates with other sections of the specifications and may not be complete in itself.

5.1 FACTORY INSPECTION

5.1.1 The Contractor shall provide and maintain an inspection system acceptable to the Owner. This system shall cover supplies under this contract and shall tender to the Owner for acceptance only supplies that have been inspected in accordance with the inspection system and have been found by the Contractor to be in conformity with contract requirements. As part of the system, the Contractor shall prepare records evidencing all inspections made under the system and the outcome. These records shall be kept complete and made available to the Owner during contract performance and for as long afterwards as the contract requires. The Owner may perform reviews and evaluations as reasonably necessary to ascertain compliance with this paragraph.

The Owner has the right to inspect and test all supplies called for under this contract, to the extent practicable, at all places and times, including the period of manufacture, and in any event before acceptance.

5.2 FACTORY TESTS

5.2.1 Strand Test - Each strand of each armature coil shall be tested at a 120[57] volts alternating current (ac) using a procedure approved by the Contracting Officer to demonstrate that it has maintained its electrical isolation from every other strand throughout the manufacturing process. The test shall be done after the coils have been pressed to consolidate the strands. The manufacturer shall submit the proposed test procedure to the Contracting Officer for approval. Finished coils that fail the strand test shall not be reworked, but shall be rejected and not furnished as part of this contract.

5.2.2 Each coil of the armature winding shall be given dielectric tests at the factory after completion of manufacture and immediately prior to packing for shipment. Each armature coil or coil side shall be given an ac test at 60 Hz, and 1.5 times (2 times rated voltage plus 1000),[58] root mean square, for one minute. If 50 Hz is used, the duration of the test shall be 72 seconds.

If multiple-turn coils are used, each coil shall be given an induced or applied dielectric (surge) (turn-to-turn) test to demonstrate the ability of the coil to withstand the dielectric stresses associated with traveling waves. The test voltage to be applied to each coil shall have a peak value equal to at least 21 times the turn-to-turn operating voltage times the number of effective turns per coil.[59] The effective turns-per-coil is equal to the number of turns-per-coil minus one. The time duration of the test voltage shall be at least 3 but not more than 10 seconds. The test shall be performed in accordance with IEEE 552. The Contractor shall furnish a description of the procedure for performing the test.

Coils failing either the high-potential or the induced- or applied-dielectric tests specified above shall not be reworked or refinished, but shall be rejected and not furnished as part of this contract.

5.2.3 The Contractor shall perform power-factor tip-up tests at the factory in accordance with the latest revision of IEEE 286, Measurement of Power-Factor Tip-Up of Rotating Machinery Stator Coil Insulation. The tests shall be made separately on each coil. The test shall be made by measuring the power factor (expressed in percent) at 2 kV and 8 kV,[60] root mean square, and determining the numerical difference in the values. If the numerical difference is greater than 1%[61] (0.01 power factor), the coil shall be rejected. Measurements may be made by energizing the conductor and grounding the slot portions by means of a clip attached to the center of each leg. The test value of tip-up shall be stamped, marked, painted, or noted by some other means on each coil so that the values can be easily identified at the time of installation.

Test reports, indicating the measured power factors of each coil tested, shall be furnished to the Contracting Officer.

5.2.4 Dissipation Factor Test - In addition to the power factor tip-up test, every tenth coil produced shall be given a dissipation factor test. This test shall consist of subjecting the bar, using the same test setup as the power factor tip-up test, to ac voltages of 20 through 200% of rated line-to-ground voltage. To compensate for occasional measurement anomalies, the averaging of a single step value not meeting the specified criteria with the next highest step will be permitted.

Should the two steps have different acceptance criteria, these also may be averaged. For each coil that fails the dissipation factor test, four additional coils shall be tested. The dissipation factor shall be measured as a function of voltages at each 20% interval of rated voltage, that is, 20, 40, 60, 80, 100, 120, 140, 160, 180, and 200%. Dissipation factors shall not exceed the values given in the following table:[62]

For each 20% interval between:	and:	The dissipation factor shall not increase by more than:
20%	60%	0.0015
60%	120%	0.003
120%	200%	0.004

5.2.5 Partial Discharge Test[63] - Each coil shall be subjected to a Partial Discharge Test in accordance with ASTM D1868 - Detection and Measurement of Partial Discharge (Corona) Pulses in Evaluation of Insulation SystemsPartial discharge measurements shall be made with the bars subjected to 12 kVA and 35 kV, 60 Hz ac. External interference shall be eliminated by having the conducting surface on the slot portion of the coil by shorting out by spiralling copper shooting wire around the coil the entire length of the conducting treatment, with aluminum foil in good contact with conducting

surface of by another method approved by the Contracting Officer. PDA-H method of testing will be used and the test results will be submitted to the Owner.

5.2.6 Surface resistivity (SR) tests shall be conducted on both sides of the four graded portions of each coil to determine the SR values of the gradient paint or the tape. Coils with any resistivity value outside the predetermined acceptable range shall be corrected.[64]

5.2.7 A lights-out test[65] shall be conducted on a 5% sample or a minimum of 10 coils of each set of coils produced. Coils shall be tested at a voltage level of 16 kV rms, 60 Hz, applied to the conductor with all strands tied together and the surface of the slot portion grounded. If evidence of visible corona is found on any coil, another sample of 10% or a minimum of 20 coils shall be tested. If additional two or more coils are found with evidence of visible corona, the entire set of coils shall be tested.

The Contractor shall investigate and correct the SR and grading system problems for the entire set of coils if evidence of visible corona is observed on any coil tested. If the Contractor fails to correct the problems after two trials, the Owner may reject the set of coils.

5.2.8 Each RTD that will be located in the armature winding shall be tested for accuracy by comparison with a suitable standard. Each detector shall be tested at 25, 80, (100 for platinum,) and 120°C.

Each RTD shall be tested for insulation resistance by applying 1000 volts between the detector leads, tied together, and the RTD filler strip surfaces. Continuity tests will be performed between RTD leads with a low voltage tester. RTDs failing the tests will be rejected and shall be replaced.[66]

The tests shall be made in the presence of an Owner's inspector. Test reports shall be furnished to the Owner as submittal data prior to shipment of the RTDs.[67]

5.2.9 Spring-Type Filler Material Compression Test[68] - 2% of the spring-type filler material shall be subjected to this test. Failure to pass this test shall require the redesign and retest of the spring material. The spring height is defined as the total height of the spring minus the material thickness (the distance that the spring can be compressed). Samples of each size to be used in the installation shall be tested. The force required for an 80% reduction in spring height shall be at least 110 psi (0.76 MPa). After this measurement, the test samples shall be conditioned by compressing them 100% (completely flat) between two plates. They shall be kept at 120°C for 168 hours. After condition, the force required for an 80% reduction in spring height shall be at least 70 psi (0.48 MPa). The uncompressed spring height shall have shrunk less than 20%. All test results shall be submitted at least 30 days prior to shipment of the springs.

5.3[69] PROTOTYPE COIL TESTING[70]

5.3.1 General - Four[71] sample coils, resembling the Contract winding in all respects and submitted before formal production run shall be (tested at the Contractor's facility) (delivered to an independent testing facility) (delivered to the Owner's testing facility).[72] (The Contractor may witness the tests.) (The Contractor shall submit test procedures to the Owner. Concurrence of the test laboratory procedures will be signed by both the Owner and the Contractor. The Owner shall be informed of the start and expected completion dates of each test at least 21 days before testing is to begin.)

The prototype coils, including semiconducting and gradient materials, shall be in all respects representative of the coils to be used in the unit and shall be identified by separate serial numbers. These prototype coils will be subjected to destructive tests including voltage endurance tests, thermal cycling tests and breakdown tests.

The winding insulation system and its corona suppressive systems shall not exhibit any damage such as de-bonding of paint from the coil surface or suffer any failure. Light discoloration, for example from light blue to grey, is permitted, but not physical deterioration of the winding surface. Slight touchup of the paint systems is only allowed on the same spots once.

One coil[73] will be selected from the set of prototype coils and be dissected at six locations. Dissections are to be done in the middle of the two slot legs and at the four knuckle ends where the conductive and grading paints/tapes are overlapped. The number and size of voids within the ground wall insulation system will be measured and counted. Tape folds and the amount of strand misalignment will be checked. This single dissected coil shall serve as an indicator of the coil design and shall represent the other nine prototype coils. If dissections from the coil include any voids greater than 0.8 x 10 inches (20.32 mm x 254.0 mm) in size or voids created by tape folds bending significantly backward upon themselves or strand misalignment greater than +/- 0.0625 inches (1.5875 mm) from the nominal dimensions, then the other nine coils will be considered as a failure of the coil manufacturing and will be rejected. These coils will be returned to the Contractor and other tests will not commence. Only after the dissected coil, with a minimal amount of voids, debris, tape folds, and strand misalignment, passes the dissection test, as determined by the laboratory and agreed to by the Contracting Officer, the following testing will commence.

5.3.2 Surface Resistivity - During the manufacturing of the prototype coils, the Contractor shall develop an acceptable range of SR values on the approved gradient paint or tape by using the Owner-furnished instrument. The instrument will give the direct measurement of SR in megohms/square or gigaohms/square with a 500-volts megohm meter and a Doble probe. This established range of SR values that prevents discharge activity at the inner end next to the slot portion and at the outer end of the graded portion of the coil shall be used as the acceptable criteria for the manufacturing of the production coils.

5.3.3 Lights-Out Test – Lights-out tests shall be performed on the prototype coils to confirm that there is no evidence of visible corona at 16 kV rms,[74] 60 Hz.

5.3.4 Dimensional Checks[75] - The finished prototype coils without being heated shall be tested in the dummy stator core for dimensional checks. The prototype coils shall be able to be side packed full depth of the ripple spring side fillers furnished. The ripple spring side packing thickness shall not be less than 0.030 inch (0.762 mm). The compression of the side fillers shall be not less than 70% and not more than 90% of the maximum compression through the length of the core model.

Each coil shall withstand a 37 kV, that is, 1.17x(2E + 1), 60 Hz test prior to the thermal test.

5.3.5 Voltage Endurance Tests - After coils pass the above acceptance tests, voltage endurance tests will be conducted on four coils in accordance with IEEE Standard 1043 at 30 kV, 60 Hz, and 100°C for a minimum of 400 hours. (20 kV, 60 Hz, and 110°C for 250 hours for a 20 kV machine) Repair of paint or tape during the test will not be allowed.

Breakdown of the ground wall insulation leading to insulation puncture of (not more than)[76] one of the prototype coils prior to the elapse of 400 hours in the voltage endurance test shall constitute acceptance of the coil design and the Contractor may proceed with production of coils upon notification by the Contracting Officer. The accepted set of prototype coils will become the property of the Owner.

Failure of (any coils) (two or more coils) prior to the elapse of 400 hours in the voltage endurance test, or any de-bonding between the conductors and turn insulation or delamination within the groundwall observed on dissections in coil after the thermal cycling test will constitute failure of the coil design. The Owner may perform additional tests to determine the cause of failure on any failed coil(s). Within 21 days from the date of notification by the Contracting Officer of failure by the dissector or by testing, the Contractor may analyze the failure and improve the design and fabrication procedures. The Contractor may then submit such analysis, modified design and modified production procedures to the Contracting Officer for approval prior to the manufacturing of a second set of prototype coils, and repeat the shipping for retesting.

5.3.6 Voltage Breakdown Tests[77] - This test consists of subjecting selected coils to a 60 Hz test voltage of 30 kV rms at a steady state temperature of 90°C continuously to breakdown. Under these test conditions, the first coils must not fail before 250 hours and all other coils must not fail before 500 hours. Prior to performing Accelerated Life Tests, the coil manufacturer shall perform a power factor tip-up test on the selected bars. Should the coil manufacturer propose to use 50 Hz power frequency, the above hours to fail shall be increased by 20%. The tests shall be performed in accordance with IEEE Standard 1043.

5.3.7 Prototype Destruction Test[78] - One coil shall be destructively tested using an ac Hi-pot test set. The coil shall have its voltage ramped to 40 kV and held there for (1 minute) (3 minutes). It shall then be raised in 5 kV steps and held at each step for (10 seconds) (3 minutes). The voltage of failure shall then be recorded. Coils will be dissected to determine the primary cause of failure. Delaminations, excessive void content, improper resin cure, or any other dielectric problems shall be noted.

5.3.8 Thermal Cycling - The coils[79] shall be thermally cycled 200 times[80] from 40°C to a copper temperature of 155°C[81] and in accordance with IEEE Standard P1310, Trial Recommended Practice for Thermal Cycling Tests on Large Stator Bars and Coils. One coil will be dissected at three locations in the middle and at the knuckles. Other coils will be subjected to a high potential breakdown test for evaluation after the thermal cycling test. (Heating will be accomplished by circulation necessary current [Contractor to furnish calculations for Owner's review] to obtain a copper temperature of 150°C within 30 to 60 minutes. Forced-air cooling will reduce the copper temperature to 40°C within 50 minutes.)[82]

Absolute dissipation factor (power factor) and partial discharge test shall be done on each coil prior to commencement of the thermal test and after 10, 50, 100, and 200 cycles. Physical measurements of each coil's width and depth shall be made at five equally-spaced locations along the slot portion of the bar. Measurements shall be made initially, after 10, 100, and after 200 cycles. After the physical measurements are made, each coil will be tapped and any delamination of the ground wall from the copper shall be noted.

5.4 PRODUCTION COIL TESTING[83]

5.4.1 General - During production of stator coils, two sets of four sample coils are to be selected by the Contracting Officer for testing by the testing facility under contract to the Owner. Two sample coils at approximately one-third of the way through the production of each set of the stator windings, and another two sample coils at approximately two-thirds of the way through the production of each set of stator windings, will be selected by the Contracting Officer. The coils shall be shipped by the Contractor to the testing facility under contract to the Owner for conducing tests and inspections. The Contracting Officer will identify sample coils by placing a tag on each coil bearing the name and number for each set. These sample coils will be subjected to destructive tests including voltage endurance tests.

5.5 INTERLAMINAR (STATOR CORE) INSULATION TESTS[84]

Before proceeding with the installation, the Contractor shall inspect the stator slots and other parts of the generator for damage thereto. The Contractor shall, at the Contractor's own expense, restore the stator core to a tight and level condition and check it for any looseness of iron and for any condition that might contribute to localized heating to such an extent as to reduce the output or affect the magnetic circuits of the new armature winding. (The Owner will remove at least two coolers to accommodate inspection of the outside area of the core for any unusual conditions.)[85] Any unsatisfactory condition found

shall be reported to the Contracting Officer with a recommendation on the repair procedure the Contractor proposes to follow and an estimate of time to complete the repair.

5.5.1 Loop Test [86] - (Choose either this or the next paragraph for core testing or delete if no core test is desired.) The Contractor shall test the stator core lamination assembly for hotspots by establishing approximately normal working flux density, until temperature stabilizes or for 60 minutes and shall clean up and repair visible burned spots, or any hotspot exceeding 5°C[87] above the core ambient temperature as may be detected during the flux test. The test shall be performed as outlined in Section 8.1.10 of IEEE 56. In conducting this test, the Contractor shall measure the voltage induced in a separate circuit consisting of one or more conductors that are physically displaced from the existing coil and that are wound around the stator core. This voltage shall be read for increasing values of amperes in the circuit establishing flux density. Values of loop voltage shall be plotted against circuit amperes to determine a curve. The knee of the curve shall be used to determine the current necessary to establish optimum flux density for the test. The ambient temperature of the core and any detectable hotspots shall be recorded at intervals not exceeding 10 minutes during the test and for 60 minutes after the existing circuit has been de-energized. The Contractor shall be responsible for supplying all cable necessary to perform this test. Time shall also be recorded when each set of temperature readings is taken. After all corrections are made, working flux density tests shall again be applied to demonstrate that faults have been corrected. After successful completion of this test, the core-clamping studs shall be rechecked.

5.5.2 ELCID Test - The interlaminar stator core insulation shall be tested using the above induction method or the "El Cid" method. In case of the latter, a uniform core temperature of about 70°C shall be produced for checking local hot spots on the core. A deviation of 5°C[88] from the average core temperature shall be considered defective. Any deficiencies shall be corrected with the Owner's advance approval.

5.6 FIELD TESTS

The Contractor shall be responsible for all work required to perform the field tests except as stated in "Work and Materials to be Provided by Owner."

5.6.1 Daily Tests[89] - Once every 24-hour period,[90] the coils installed during that period, including final installation of slot filler and wedges, shall be given the following tests. Any coil that fails during the tests shall be removed and replaced with a new coil by the Contractor at the Contractor's own expense.

(a) DC high potential tests[91] - 1.7 times (2 x rated plus 1000) volts direct current (dc) for 1 minute. This test is to be made after the coils have been tied to the surge rings and wedged. In the event a coil fails during the test, it shall be removed and replaced with a new coil at the Contractor's expense. [92]All parallel rings, if used, shall be high potential tested at the same voltage for a period of one minute before they are connected to the coils.

(b) Induced or applied dielectric tests[93] - If multiturn coils are used, each coil shall be given either an induced or applied dielectric test. The test voltage shall have a peak value equal to at least two-thirds of 21 times the turn-to-turn operating voltage times the number of effective turns per coil.[94] The effective turns per coil is equal to the number of turns per coil minus one. The time duration of the testing voltage shall be at least 3 but not more than 10 seconds. In the event a coil fails during this test, it shall be removed and replaced with a new coil at the Contractor's expense.

(c) Strand-to-strand tests[95] - If multiturn coils with external transposition are used, a strand-to-strand test shall be made on each complete circuit before that circuit is connected to the parallel rings or terminals. A 120V ac 60W light bulb will be used to check for shorted strands. No shorted strands will be accepted.

(d) Interference test[96] - The winding shall be checked by the Contractor to confirm that no part of the winding extends into the radius of the stator bore.

(e) RTD insulation and continuity test - Immediately following installation, each detector shall be tested for continuity and then insulation resistance momentarily at 500[97] volts between the leads (tied together) and ground. The insulation resistance test shall be repeated immediately after the slot is wedged.

5.6.2 End Turn Frequency Response Test (Modal Analysis Test)[98] - After completing the installation of the end winding support structure, a frequency response test is to be performed on each connection to confirm that it does not resonate at frequencies of 120 Hz +/-10% in the vertical, horizontal, or tangential direction in excess of 0.5 millimeter/kiloNewton. Should any end turn fail this test, the Contractor shall submit a proposed solution to the Owner, and upon acceptance, shall apply it to the generator.

5.6.3 Insulation Resistance and Polarization Index Test[99] - Insulation resistance and polarization index (PI) tests shall be made on each phase as described in IEEE 43. In all cases the phases not under test shall be solidly grounded. Tests shall be made at above 5000Vdc. Winding insulation resistance shall not be less than 29.6 megohms, corrected to 40°C. A PI value of 3+ shall be obtained after dryout.

5.6.4 AC Hi-Pot Test[100] - After the winding has been completely assembled, dried out, or cured, if necessary, and before the installation of the rotor, the Contractor shall, at the Contractor's expense, give each phase of the armature winding an ac 60-Hz dielectric test of two times (rated voltage plus 1000) volts, root mean square, for one minute, in accordance with ANSI C50.10 and IEEE 115.

The Contractor shall furnish a potential transformer and calibrated voltmeter to check the voltage applied by the Owner's ac, high potential test set. However, this equipment need not be furnished if the Contractor accepts the accuracy of the voltmeter supplied with the high-potential set.

5.6.5 DC Absorption Test - After the Contractor successfully completes the ac dielectric test, the Owner will give each phase of the armature winding a dc dielectric test to 30 kV[101] on a time-voltage schedule selected by the Owner to demonstrate absorption values of the winding. In the event any coils fail during the ac or dc dielectric tests, the Contractor shall locate and replace them at the Contractor's sole expense.

5.6.6 Armature Resistance Test - After completion of each armature winding and prior to completion of the main lead connections, the Contractor shall measure the armature winding resistance in accordance with the latest revision of IEEE 115, Test Procedures for Synchronous Machines. If resistance variance between the highest and lowest phases exceeds 0.5% or deviate from the calculated value by more than 1%, the Contractor shall investigate the reason and submit an explanation in writing to the Owner. The Contractor is reminded that these values of armature resistance will be used to determine compliance with the warranted losses.

5.6.7 Lights-Out (Blackout)/Corona Test[102] - After all field tests have been successfully passed and before painting, the stator shall be given a lights-out (blackout)/corona test. The winding shall exhibit no visible corona when tested at 10 kV[103] (to ground), 60 Hz, with the winding in darkness. The stator frame shall be enclosed in a plastic tarp to keep it in darkness. During the test, all three phases shall be excited simultaneously.[104] Should any coils show visible signs of corona, the Contractor shall make repairs to the corona suppression system and retest the winding until no visible corona is detectable with the naked eye.

5.6.8 Warranty Testing[105] (Acceptance Testing) - After the generator, including its auxiliary equipment, has been reassembled by the Owner, it shall be tested, by and at the expense of the Contractor, to determine whether or not the Contractor's warranties and the requirements of this contract have been fulfilled. (The unit to be tested will be determined by the Owner.)[106] The tests shall be made in accordance with the applicable standards of IEEE and of ANSI except as herein noted. All tests will be witnessed by the Contracting Officer or a representative.

(a) Open-circuit saturation test.

(b) Short-circuit saturation test.

(c) Zero-power factor saturation test.

(d) Heat runs[107] - Heat runs shall be made to determine the temperature rise of the various parts of the generator when operating continuously at 50%, 75%, and rated or maximum kilovolt ampere, rated power factor, 60 Hz, and at rated volts, with existing reservoir conditions. The temperature rise of the armature winding shall be determined by the embedded detector method, and the temperature rise of the field shall be determined by the resistance method. The average temperature indicated by the highest reading temperature detector during the period of stable

temperature shall be used to determine the temperature rise of the armature winding. The average temperature of the air leaving all the surface coolers of the generator during the period of stable temperature shall be used as the ambient temperature on which to base determination of the temperature rise of the armature and field winding. Sufficient thermometers, thermocouples, or resistance temperature detectors shall be placed in the cooled air discharge not more than 6 inches (15.24 cm) from the surface coolers to obtain accurate temperature information.

The following procedure shall be used for locating the temperature devices in the cooler air discharge in order to obtain accurate average temperature:

Not less than 20 temperature devices shall be installed in the path of the discharge air from one cooler. The devices shall be installed not more than 6 inches (15.24 cm) from the face of the cooler and shall be spaced at approximately equal intervals. With the generator operating under approximately-rated load and with the cooling water supply adjusted as it will be used during the heat run test, temperature readings of all temperature devices on this one cooler shall be observed and recorded, and the readings shall be averaged. The average temperature so determined shall then be used to locate at least four temperature devices in the air discharge from each cooler in positions that will represent average temperature. The average of all temperature devices (at least four per cooler) will then represent the ambient air temperature for the generator during the period of stable temperature. The average reading of all temperature devices (at least four per cooler) during the period of stable temperature will be used as the ambient temperature on which to base the temperature rise of the various machine parts.

(e) Deviation factor of waveform - Oscillograms shall be taken of the waveform of the voltage of each phase of the armature winding when the generator is operating at rated voltage and open circuit.

(f) Loss test[108] - This test shall include the determination of the friction and windage losses, I^2R losses in the armature winding, and stray-load losses with the generator uncoupled from the turbine. The tests shall include measurements for determining a loss curve extending from 25% to 100% of rated kilovolt amperes at not less than four load points.

Tests other than tests listed in (a) and (b) above shall be made at a time convenient to the Owner, not to exceed 18 months following completion of installation of the (second) (last) armature winding.

The Contracting Officer will keep the Contractor advised as to the time when these field tests can be conducted and will notify the Contractor 30 days in advance of the dates the tests are to be performed. The waiving of any test, on either generator, by the Owner shall not constitute relinquishment of the

Contractor's responsibility to fully meet the requirements that were to have been demonstrated by that test. All instruments used for the tests shall be calibrated by and at the expense of the Contractor before and after the tests by comparison with suitable standards. All test reports shall be furnished as required by subparagraph C.1.4.c.

The Contractor's installation foreman or his representative shall remain at the job site until he obtains a formal signed release from the representative of the Contracting Officer verifying that the field tests required under this paragraph have been completed in accordance with this solicitation/specifications.

5.6.9 Machine Characteristics Tests[109] - The following tests shall be performed on the first of the upgraded generators. The tests shall be made in accordance with the most current applicable IEEE 115 Standard.

5.6.10 Sudden short-circuit tests shall be conducted to show that the mechanical design of the machine is adequate to withstand the stresses due to short circuits and related abnormal operating conditions. These tests shall also be used to determine the characteristics listed below:

(a) Direct-Axis Synchronous Reactance (X_d).
(b) Quadrature-Axis Transient Reactance (X_q).
(c) Direct-Axis Transient Reactance (X'_d).
(d) Direct-Axis Subtransient Reactance (X''_d).
(f) Quadrature-Axis Subtransient Reactance (X''_2).
(g) Negative-Sequence Reactance (X_2).
(h) Zero-Sequence Reactance (X_0).
(i) Positive-Sequence Resistance (R_1).
(j) Negative-Sequence Resistance (R_2).
(j) Zero-Sequence Resistance (R_0).
(l) Direct-Axis Transient Open-Circuit Time Constant (T'_{do}).
(m) Direct-Axis Transient Short-Circuit Time Constant (T'_d).
(n) Direct-Axis Subtransient Open-Circuit Time Constant (T''_{do}).
(o) Direct-Axis Subtransient Short-Circuit Time Constant (T''_d).
(p) Short Circuit Time Constant (T_a).
(q) Load Angle.
(r) Short-Circuit Ratio.

5.7 GENERATOR INSPECTIONS AFTER OPERATION

5.7.1 During the warranty period, there shall be at least three [110] inspections made during which the Contractor's armature winding specialist or specialists and representatives of the Contracting Officer shall participate together in a thorough inspection of all equipment and materials furnished by the Contractor. The Owner will give the Contractor no fewer than 20 calendar days' prior notice of the date for each inspection. The Owner will make the unit available for the inspections and may at its option remove the rotor or sufficient

poles to permit a thorough inspection, at no cost to the Contractor for each inspection period. The Contractor will be responsible for all expenses incurred by the Contractor's representative or representatives in connection with all inspections, including costs of reports of results of the inspections.

Inspections of the armature winding (on units _____, _____, and _____) shall include those items listed in the method of periodical inspection and testing of the winding after installation, submitted by the Contractor and the following items:

(a) Determine that all coils and other materials are tight in the slot and have not slipped up or down.

(b) Determine that all wedges, radial packing, blocking, and lashing are tight.

(c) Inspect stator frame and/or winding components for abnormalities that shall include, but not be limited to:

(1) Loose stator laminations, core clamping bolts, and fingers, and hotspots or paint discolorations.

(2) Presence of dust or powder that may be related in any way to deterioration of the stator winding.

(3) Unusual movement, cracking, or distortion.

(4) Ring buses and main leads.

(d) Perform corona probe; programmable dc, high-voltage ramped test; coil-surface, contact-resistance tests; or other agreed-upon tests for possible internal slot or end-turn corona. The Owner will furnish all test equipment for performing the corona probe or programmable dc, high-voltage ramped test and coil-surface, contact-resistance test. The Contractor shall furnish all test equipment required for other agreed-upon tests.

After each inspection, the Contractor shall furnish five copies of a certified report of the results of the inspection for approval of the Contracting Officer. Each report shall incorporate a method of checking the winding as described above. Any repairs found necessary shall be performed by the Contractor under the clause in subsection I.2 entitled "Warranty."

DIVISION 6 - DELIVERIES OR PERFORMANCE

Note - This section correlates with other sections of the specifications and may not be complete in itself.

6.1 TIME OF DELIVERY

[111]The Owner requires complete delivery of the armature winding(s) under Item 1 to be made on or before (_____) (the dates listed below):

First winding ..... on or before _____
(Second winding..... on or before _____
Third winding..... on or before _____)[112]

[113]Time of delivery of the initial set of prototype coils for testing including an allowance for the Owner to complete voltage endurance testing of the initial set of prototype coils and complete delivery of a second set of redesigned prototype coils for retesting by the Owner if the initial set of prototype coils fail the voltage endurance testing _____[114] days after award of Contractor.

The Owner will complete testing of the second set of coils within _____ [115] days of receipt.

Time of delivery of complete set of production coils for testing within _____ [116] days after award of contract.

The Owner will complete testing of production coils within _____[117] days of receipt.

Time of complete delivery of complete set of stator windings to powerplant within _____[118] days of award of contract.

6.2 TIME OF INSTALLATION

(a) Installation - The Owner requires complete installation (and testing) of (the) (each) generator armature winding not later than the date specified below, provided that the Contractor will have the exclusive use of the generator stator with the generator rotor (and armature winding removed) on or before _____. The Contractor shall notify the Owner 30 calendar days in advance of the time he proposes to commence fieldwork on the generator.

Complete installation (including testing of the new armature winding(s) is required (on or before _____) (within _____ calendar days after the date the Contractor is required to begin installation, with a planned commencement date, for each winding, falling within the period _____ to _____).

(However, in the event of failure of [the] [an] existing winding, the Contractor may be directed to begin installation as early as _____.)[119]

Offers that specify later installation (and testing) completion dates than stated above will not be considered.

The installation (and testing) dates or specific periods above are based on the assumption that the Owner will make award by _____. Each installation (and testing) date in the installation (and testing) schedule above will be extended by the number of calendar days after the above date that the contract is in fact awarded, provided that installation (and testing) shall be completed within _____ calendar days after the date the Contractor is directed to begin installation and testing shall be completed not later than 18 months after completion of installation of the (second) (last) armature winding.

[120](The Owner, at its sole option, reserves the right to direct the Contractor to expedite the installation and testing work for which the Contractor will be paid the additional sum of [_____], per armature winding, for each directed calendar day prior to _____ he completes the installation and testing work for such armature winding.)

If the generator stator is not available for the Contractor's exclusive use within the time specified above, or if the Owner fails to complete endurance testing within the indicated time, an equitable adjustment will be made in the contract.

If the Contractor is required to perform any repair work not specifically provided for under these specifications, and such repair work, in the opinion of the Contracting Officer, delays the installation of the armature winding, the Contractor shall be entitled to an extension of the installation date equal to the delay in the installation time of the armature winding.

The acceptance tests shall be made at a time convenient to the Owner, not to exceed 18 months after completion of installation of the (second) (last) armature winding, and the time required to make these tests will not be considered as part of the installation time specified in the schedule. The Contractor shall be given not less than 30 calendar days' prior notice of the date testing shall begin.

For the work connected with the installation work only, the capacity of the Contractor's construction plant, sequence of operations, method of operation, and the forces employed at the job site shall, at all times during the continuance of the contract, be subject to the approval of the Contracting Officer, and in respect to all work under the contract, shall be such as to ensure the completion of the work within the specified time.

6.3 LIQUIDATED DAMAGES – SUPPLIES AND SERVICES

The required time for delivery of the new armature winding including spare parts under Item 1 is specified in the schedule. If the Contractor refuses or fails to perform or to make complete delivery of the equipment within the required time, or should the contract be terminated, the amount of liquidated damages to be charged for failure to perform or for failure to deliver the armature winding or any part thereof, within the required time will be $_____[121] for each calendar day of delay, provided that for purposes of assessment of the foregoing liquidated damages, delivery of the armature winding will be exclusive of certain minor specified materials that have a limited shelf life and that the Contractor has previously recommended they not be shipped until immediately prior to their installation.

(The required period of time for removing the existing winding and for installation, including testing, of the new armature winding entitled "Time of Delivery;" or should the contract be terminated, the amount of liquidated damages to be charged for failure to perform or for failure to complete the installation and testing of the generator winding, or any part thereof, within the required time specified, will be _____[122] for each calendar day of delay.)

6.4 PRODUCTION SCHEDULE AND PROGRESS CHART

The Contractor is required to submit a milestone schedule with the bid to show completion of the following work activities (for each unit)*:

- Completion of Engineering
- Delivery of Critical Material
- Completion of Coil Manufacturing
- Removal of Old Winding[123]
- Completion of Stator Iron Repair and Preparation
- Completion of Winding Installation

The Contractor will be required to furnish a detailed coil manufacturing, testing, and installation schedule 30 days after award of contract.

6.5 WARRANTY

6.5.1 General - The Contractor warrants that for a period of five years[124] after the beginning of operation.

During the foregoing five-year warranty period, routine maintenance by the Owner shall be limited to the normal cleaning and replacement of expandable and readily accessible parts and shall not include any replacement of major parts required as a result of a failure, such as a dielectric breakdown of an armature coil.

Routine maintenance by the Owner shall not include testing or corrective work to reestablish and maintain tightness in the stator slot assemblies, such as replacement of slot side fillers or slot wedges, or retreatment of coil surfaces. However, the Owner will perform such diagnostic tests as it selects that are not damaging to the insulation system. The new armature windings shall be designed for a useful life of not less than 25 years, when operated under the conditions specified.

6.6 QUALITY ASSURANCE

The price of each generator armature winding will be reduced $_____[125] for each kilowatt that the actual armature winding I^2R losses, as determined by test, exceed the warranted losses at rated volts, rated frequency rated power factor, overexcited, and rated-kilovolt ampere output. Any reduction so made will be based on losses as determined from field tests performed by the Contractor in accordance with the field tests specified rather than any previous tests made by the Owner.

[126]The price of each generator armature winding will be further reduced $_____ for each of 1/100 of 1% that the actual kilowatt capacity is below the required capacity and temperature specified.

Liquidated damage specified for failure of each stator winding to meet the stator resistance values specified is in addition to the liquidated damages for failure to deliver, install, or test in the time specified.

[127]The maximum sum of liquidated damages of this article and liquidated damages for time of delivery, installation, and testing, will not exceed 50% of the Contractor's total bid price.

DIVISION 7 - LIST OF DOCUMENTS, EXHIBITS, AND OTHER ATTACHMENTS

Note - This section correlates with other sections of the specifications and may not be complete in itself.

7.1 DRAWINGS, GENERAL

7.2 LIST OF DRAWINGS

The attached drawings listed below are made a part of this solicitation:

1. _____ - Location Map.
2. _____ - General Arrangement - Transverse Section.
3. _____ - General Arrangement - Plan - Floor Elevation.
4. _____ - Generator Outline.
5. _____ - Switching Diagram.
6. _____ - Ventilation Pattern.
7. _____ - Stator Coil Detail.
8. _____ - Stator Winding Connection Diagram.
9. _____ - Stator Winding RTD Arrangement.
10. _____ - Stator Core.
11. _____ - Detailed Assembly of Stator Coil End.
12. _____ - Rotor Winding Assembly.

END OF SPECIFICATIONS

* Choose or select as appropriate to application and organization's policy.

SAMPLE SPECIFICATIONS (OUTLINE)

GENERATOR STATOR REHABILITATION

SUMMARY

This specification is prepared for the rehabilitation of any generator stator at _____ Generating Station. It covers the site-specific contractual requirements and technical specifications for the replacement of the stator core and stator winding of the generator. The new core and stator winding may have different physical dimensions, arrangement and configuration, and/or higher electrical outputs (megavolts amperes [MVA] and/or megawatts) and improved thermal rating than the original design, but they shall fit inside the existing stator frame and generator housing. A change of air gap dimension may be offered as an option but not a substitution. However, the same cooling arrangement and excitation requirement shall be maintained.

TS1 - GENERAL INFORMATION AND REQUIREMENTS

TS1.1 SITE

TS1.2 GENERAL INFORMATION

The generator to be rehabilitated is one of _____ identical units in the Station. The vertical, hydraulic generators were manufactured by _____ in _____.

.1 Generator Data

Type
Frame #
Output
Power factor
Phases
Voltage (phase)
Current (line)
Frequency
Poles
Speed

General dimensions (nominal):
Stator frame inside diameter
Stator frame height
Stator core top clearance
Stator core bottom clearance
Rotor outside diameter
Rotor pole height
Air gap

Weights:
Stator
Rotor

(a) Stator Core
Bore diameter
Core height
Number of slots
Slot width
Slot depth
Wedge seat

(b) Stator Winding
Manufacturer
Type
Circuit connection
Coil throw

Coils per group
Thermal rating
Maximum temperature

(c) Neutral Grounding
Grounding transformer

.2 Exciter
Manufacturer
Type
Power output
Voltage
Current
Rotating exciter weight

Note: This rotating exciter may be replaced with a solid state exciter during the generator rehabilitation or at some other time in the future.

.3 Cooling
Method
Air flow

.4 Machine Characteristics
(a) Reactance, p.u. on _____ MVA @ _____ kV

X_d (saturated)
X_d (unsaturated)
X_q (unsaturated)

X'_d (saturated)
X'_d (unsaturated)
X'_q (unsaturated)

X''_d (saturated)
X''_q (unsaturated)

X_0
X_1
X_2

(b) Time Constants (second)
T'_{do}
T''_{do}
T''_{qo}
T_a

(c) Field Characteristics
Field resistance R_f:
Per-unit field current
No-load field current
Full-load field current
Per-unit field voltage
Ceiling voltage
Minimum field voltage
Full-load field voltage

(d) Other Data
Short circuit ratio
H Factor
Saturation Values

.5 Turbine
Manufacture
Type
Output (rated)
Head
Rotation
Governor

Note: The existing governor may be replaced with an electronic version during the generator rehabilitation or some other time in the future.

.6 Powerhouse
Main building dimensions
Allowable load on floors

.7 Cranes
There are _____ powerhouse cranes
Capacity of main hoists
Capacity of auxiliary hoist
The combined capacity of the two cranes is _____ pounds

TS1.3 SITE SERVICES

.1 By the Contractor

.2 By the Owner

TS1.4 PROTECTION OF THE ENVIRONMENT

TS2 - SCOPE OF WORK

TS2.1 GENERAL

The Contractor shall supply and install all things required, unless otherwise specified in the Contract Documents, to refurbish the old generator with a new stator core and a new stator winding, shown, described, or intended in this Contract. All things that are not specifically mentioned in the Contract Documents, but which are usually expected or necessary for the efficient operation of the equipment to be provided under this Contract shall be deemed to be included in this Contract and shall be provided by the Contractor without extra charge.

TS2.2 SUPPLY OF NEW MATERIALS

The Work shall consist of the design, manufacture, testing, delivery, and installation of, but not be limited to the following:

.1 Stator Core Materials

(a) Core Assemblies

One (1) complete set of core laminations, ventilation duct and core clamping assemblies, plus _____ % spares, to accommodate the new winding specified below. The new core shall fit inside the existing stator frame and generator housing, and maintain the same air gap and excitation requirements of the existing unit.

Note: A new core with a more efficient, modern design having the same or different number of slots and dimensions as the original, to accommodate the new winding to be supplied in this Contract, may be offered as an option, NOT as an ALTERNATIVE. The physical and excitation constraints listed above shall remain in force.

(b) Winding Support Assembly

One (1) complete set of winding support structures, including _____.

.2 Stator Winding Materials

(a) Stator Winding

One (1) complete set of stator winding coils, including _____.

Note: A new winding with a more efficient, modern design having higher outputs may be offered as an option, NOT as an ALTERNATIVE. It shall be compatible with the new core offered

above. The physical and excitation constraints of the new core specified above shall remain in force.

(b) Prototype Coils or Bars

_____ sample coils, or bars whichever applicable, identical to the Contract winding in all respects, for pre-production lab tests, as specified in TS6.1.

(c) Winding Packing and Restraining Materials

One (1) complete set of winding side packing materials, _____, plus sufficient materials for additional _____% of the total slot requirement.

(d) Winding Connection Materials

One (1) complete set of winding coil or bar series connection and insulation materials such as _____, plus _____% spares. The amount of spare for materials with limited shelf life of one (1) year or less, shall be adjusted to _____% of the total.

(e) Winding Slot Wedging Materials

One (1) complete set of slot wedging system, including _____, plus _____% spares.

(f) Winding Installation Equipment and Tools

One (1) complete set of winding installation equipment, including _____, and any special equipment or tools in sufficient quantity for _____ crews working simultaneously.

(g) Winding Slot Temperature Sensor

(h) Paints

One (1) order of _____ for the stator frame. One (1) order of _____ for stator winding end turns and circuit ring buses. The paint shall be compatible with the winding materials in terms of electrical, mechanical, and thermal ratings.

TS2.3 INSTALLATION OF NEW CORE AND WINDING

The Work shall consist of, but not be limited to the following:

.1 Stator Core

(a) Old Core Removal

Note: All scrap metal shall remain the property of _____.

(b) Stator Frame Preparation

(c) New Core Installation

(d) New Core Testing

The new core shall be tested upon completion before new winding installation, as specified.

.2 Stator Winding

(a) Old Winding Removal

The old winding may contain asbestos or other materials deemed hazardous. Proper procedure for handling and disposal as required.

(b) New Winding Installation

(c) New Winding Testing

The newly assembled winding shall be tested, as specified in Clause TS6.3.2 and TS6.4.

(d) Winding RTD Installation and Test

(e) Winding Painting

The winding end turns and circuit ring buses shall be coated with _____ upon assembly.

(f) Partial Discharge (PD) Coupler Installation

TS3 - WORK SCHEDULE

TS3.1 DELIVERY AND COMPLETION DATES

.1 New Core and Winding Supply

The complete stator core and winding materials shall be delivered to Site not later than _____.

.2 Generator Availability

The generator shall be available for the Contract installation work not later than _____.

.3 New Winding Installation

The new winding shall be completely installed and ready for service not later than _____.

TS3.2 DELIVERY POINT

The delivery point shall be f.o.b.:

TS3.3 SUBMISSIONS

.1 New Core and Winding Supply

(a) Information

All manufacturing drawings with materials, dimensions and tolerances clearly shown, and explanatory information, including material type and grade shall be submitted to _____'s Representative within _____ days after the award of the Contract.

The Contractor shall submit for acceptance by _____'s Representative calculation on performance of the new stator core and winding to verify the MVA rating, maximum temperature, efficiency and losses including total core loss, stray load loss, windage loss in kilowatts (kW) at the rated load, as tendered. The basis of the calculation shall be the original dimensions of the magnetic circuit, pole dimensions and field winding, stator core and slot dimensions.

Note: The Contractor shall be responsible for determining the dimensions and information required from the existing generator for manufacturing any components to conform and fit the existing rotor air gap, stator frame and generator housing.

(b) Inspection and Test

An Inspection and Test Plan shall be submitted to _____'s Representative not later than _____ days before commencing the Permanent Work for acceptance.

(c) Notification

A written notice shall be delivered to _____'s Representative at least _____ working days prior to the accepted "customer inspection and test hold points" in TS3.3.1 (b) in order to allow making arrangements for attendance.

(d) Parts List

(e) Drawings

For the guidance of the Contractor, the detailed drawings shall include but not limited to, the following:

(i) Stator Core Lamination

(ii) Stator Core Ventilation Duct Assembly

(iii) Stator Core Anchoring Arrangement

(iv) Stator Core Clamping Arrangement

(v) Stator Core Assembly

(vi) Stator Winding Phase Connection Diagram

(vii) Stator Winding Slot Connection Diagram

(viii) Stator Coil or Bar (whichever applicable) Construction

(ix) Stator Coil or Bar Series Connection and Insulation

(x) Stator Winding End Turn Supporting System

(xi) Stator Winding End Turn Restraining Arrangement

(xii) Stator Winding Slot Packing System

(xiii) Stator Winding Slot Wedging System

(xiv) Stator Winding RTD Construction

(xv) Stator Winding RTD Installation Diagram

The preliminary drawings shall be submitted for _____'s acceptance no less than _____ days before material delivery. The final "as-built" drawings shall be submitted for _____'s acceptance no more than _____ days after completion of the installation work.

(f) Manuals

.2 New Core and Winding Installation

Information and manuals that identify each component of the Work, installation procedure and progress thereon, shall be submitted to _____'s Representative not less than _____ days prior to commencement of the installation work.

For the guidance of the Contractor, these explanatory materials shall include but not limited to, the following:

(a) Stator Core Installation Manual

(b) Stator Winding Installation Manual

(c) Stator Winding RTD Installation Manual

The final "as-built" field Manuals shall be submitted for _____'s acceptance no more than _____ days after completion of the installation work.

TS4 - SHIPPING

TS4.1 PREPARATION

TS4.2 LABELLING

TS4.3 INSTRUCTIONS

TS4.4 RELEASE FOR SHIPMENT

TS4.5 HANDLING

TS4.6 SITE CLEANUP

TS5 - SPECIFIC REQUIREMENTS

TS5.1 STATOR CORE SUPPLY

See "A Guide for Stator Core Specifications" provided in this Appendix.

TS5.1 STATOR WINDING SUPPLY

See "A Guide for Stator Winding Specifications" provided in this Appendix.

TS5.2 STATOR CORE INSTALLATION

.1 Stator Frame Preparation

.2 Core Lamination Preparation

.3 Core Assembly

.4 Core Shakedown

TS5.2 WINDING INSTALLATION

All procedures of the Work shall be accepted by _____'s Representative in advance. The execution of any Work shall be done in a manner that shall not damage or cause harm to _____'s equipment or property.

.1 Stator Core Preparation

.2 Winding Support Preparation

.3 Stator Coil or Bar installation

.4 RTD Installation

.5 Winding Connection

.6 Connection Protection

TS6 - CHECK AND TEST

TS6.1 LAB TESTS

The following winding tests shall be completed before production run:
(Describe in detail.)

.1 Voltage Endurance Test
.2 Thermal Cycling Test
.3 Dissipation Factor (DF) Measurements
.4 Pulse Height Analysis
.5 Surface Resistivity Measurements

TS6.2 FACTORY TESTS

.1 Stator Core Lamination

(Describe in detail.)
(a) Lamination Finish
(b) Thermal Stabilization Test
(c) Surface Insulation Resistivity Test

.2 Stator Winding

The new winding shall pass the following tests:
(Describe in detail)
(a) Strand-to-Strand Test
(b) Turn-to-Turn Test
(c) Dissipation Factor Tip-Up Test
(d) High Potential Test
(e) Winding Finish Check

TS6.3 FIELD TESTS

For core and winding installation, the following quality assurance checks and tests shall be included:

(Describe in detail.)

.1 Stator Core
(a) Core Shape
(b) Core Dimensions
(c) Slot Dimension
(d) Core Finish

.2 Stator Winding
(a) Winding-to-slot clearance
(b) Winding Surface Contact Resistance
(c) RTD Potential Test
(d) Winding High Potential Tests

TS6.4 COMMISSION TESTS

The Contractor shall, particularly in the case where the stator core and/or the stator winding incorporate new designs in material grade, dimensions and configuration, with claim of improved efficient and/or reduced losses, perform the following on- and off-line checks, measurements and tests:

(Describe in detail.)

.1 Phase Sequence

.2 Winding Resistance Measurements

.3 Winding Capacitance Measurements

.4 Winding Impedance Measurement

.5 Stator Wave Form

.6 Stator Telephone Interference Factor

.7 Saturation Test

.8 Three Phase Sudden Short-Circuit Test

.9 Generator Efficiency & Losses

.10 Heat Run

TS6.5 ASSESSMENT TESTS

_____ shall, at its own expense and for its own information, perform any or all following tests upon completion of the winding installation. Results of these additional tests shall not constitute acceptance or rejection of the Contract work, unless it is specified in the Contract, such as winding quality in TS5.1

(Describe in detail.)

.1 Corona Probe Test

.2 HDV Absorption Test

.3 A-c Leakage Current Tests

.4 PDA Test

.5 Load Rejection

TS7 STANDARDS

TS7.1 GENERAL

TS7.2 APPLICABLE STANDARDS and CODES

The Standards (latest edition) applicable to the Work include, but not limited to the following:

ANSI C50.10-1990	Rotating Electrical Machinery - Synchronous Machines
ANSI C50.12-198	Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications, Requirements for Salient Pole Synchronous
ASTM D4496	Test Method for D-C Resistance or Conductance of Moderately Conductive Materials
ASTM A34-96	Practice for Sampling and Procurement Testing of Magnetic Materials
ASTM A343-97	Test Method for Alternating-Current Magnetic Properties of Materials at Power Frequencies Using Wattmeter-Ammeter-Voltmeter meter and 25-cm Epstein Test Frame.
ASTM A717-95	Test Method for Surface Insulation Resistivity of Single-Strip Specimens
ASTM A937-95	Test Method for Determining Interlaminar Resistance of Insulating Coatings Using Two Adjacent Test Surfaces (Franklin Test)
ASTM D3276-96	Guide for Painting Inspectors
ASTM D3359-95a	Test Methods for Measuring Adhesion by Tape Test
CSA C22.1	Canadian Electrical Code Part I - Safety Standards for Electrical Installation
DIN 437XX	Temperature Sensors
IEEE 4	Standard Techniques for High-Voltage Testing
IEEE 43	Recommended Practice for Testing Insulation Resistance of Rotating Machinery
IEEE 95	Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage

IEEE 100-1996	Dictionary of Electrical and Electronic Terms
IEEE 115	Guide: Test Procedures for Synchronous Machines
IEEE 522	Guide for Testing Turn-to-Turn Insulation on Form-Wound Stator Coils for Alternating-Current Rotating Electrical Machines
IEEE 1043	Recommended Practice for Voltage-Endurance Testing of Form-Wound Bars and Coils
IEEE 1095	Guide for Installation of Vertical Generators Generator/Motors for Hydroelectric Applications
IEEE 1310	Trial Use Recommended Practice for Thermal Cycling Testing of Form Wound Stator Bars and Coils for Large Generator
SSPC SP1	Solvent Cleaning
SSPC SP6	Joint Surface Preparation Standard: Commercial Blast Cleaning
SSPC SP7	Joint Surface Preparation Standard: Brush-Off Blast Cleaning
NEMA MG 5.1	Large Hydraulic-Turbine-Driven Synchronous Generators
NEMA MG 5.2	Installation of Vertical Hydraulic TurboDriven Generators

TS8 - DOCUMENTATION

TS8.1 FACTORY DATA

All factory test procedures, equipment data and test results shall be recorded and submitted to _____'s Representative, prior to shipment.

Note: The ambient temperature, humidity and condition of any winding parts under tests or measurement shall be recorded.

TS8.2 FIELD DATA

All inspection, test procedures, equipment data and measurement results conducted at Site shall be recorded and submitted to _____'s Representative, no later than _____ days, upon completion of the Work,

The installation record shall include, but not limited to, the following:

(a) Stator Frame Roundness and Concentricity

(b) Stator Core Height, Roundness and Concentricity

Note: The ambient temperature, humidity and condition of any winding part under tests or measurement shall be recorded.

TS8.3 VARIANCE

All failures, or non-conformance subject to acceptance, shall be reported to _____'s Representative, prior to shipment.

TS8.4 FINAL QUALITY ASSURANCE REPORT

The Contractor shall submit _____ copies of the final Quality Assurance Report to _____'s Representative, certifying the compliance of the Work, including all assembly and test data, within _____ days of completion of final inspection and testing.

PART 8 - REFERENCE INFORMATION

It shall be the responsibility of the Contractor to obtain all pertinent information on the existing stator frame, generator cooling arrangement and any other necessary field dimensions and data that are required for the design, manufacture and installation of the new core and new winding. The following information is provided for reference only. Neither _____ nor the original issuer of the information shall be responsible for the accuracy of the content.

RI1.1 DRAWINGS

Drawing No. Title

DR8.1 Generator Top View
DR8.2 Generator Cross Sectional View
DR8.3 Rotor Spider Assembly
DR8.4 Stator Core Punching
DR8.5 Stator Cross Sectional View
DR8.6 Stator Winding Connection Diagram
DR8.7 Stator Winding Circuit Ring Bus Arrangement
DR8.8 Diagram of Hydraulic Apparatus
DR8.9 Stator Neutral Grounding Schematic

RI1.2 REPORTS

RP8.1 Commission Tests
RP8.2 Efficiency Test

Endnotes

[1] Include as needed.

[2] If the new winding can be configured as a single-turn type. This requires an appropriate number of slots and sufficient field flux.

[3] If records, the original manufacturer, or tests indicate presence of asbestos.

[4] Of the 12 specifications submitted for compilation of this specification, 10 were for hydrogenerators. This specification was assembled for hydro only but would only require slight modification for turbogenerators.

[5] Insert your company's standard submittal requirements here.

[6] If multi-turn coils are expected.

[7] If multi-turn coils are expected.

[8] Most Doble clients list the temperature for losses as 75°C. One lists it as 95°C. IEEE 115 requires that values be determined at 75°C.

[9] Delete if desired ratingis for unity power factor.

[10] Use for multi-turn coils only.

[11] These calculated quantities should be required only when a machine is being uprated, or the magnetic structure is being significantly changed.

[12] Select the appropriate requirements from the following list.

[13] For turbogenerators.

[14] For use in Canada.

[15] For use in Canada.

[16] For use in Canada.

[17] Of the dozen specifications submitted for this compilation, one client specified a 60°C rise more than the standard 40°C ambient, two clients specified 80°C more than a 40°C ambient. One client limited total temperature to 125°C, one limited temperatures to Class B requirements while requiring Class F materials, one limited total temperature to 155°C at the hottest spot, and the rest either didn't state the required the maximum allowable temperature rise or let the insulation class limit the maximum temperature rise.

[18] This section is required if the winding is reconfigured, such as when a multi-turn is replaced with a single turn, when the winding jumper configurations are changed, when a lap winding is replaced with a wave winding and vice versa, when the machine is uprated and higher field flux is intended, or when a new core is required and the manufacturer is free to change everything about the winding, air gap, and so on. If the winding is to be replaced with the same configuration, the entire section should be deleted. Four of the 12 clients' specifications include these requirements.

[19] One of the dozen Doble clients' specifications included this provision that would make it possible to reverse the line and neutral ends of the strings in the winding. The intention is to move the voltage stress from one end of a

string to the other. That one client has only reversed the leads in 1 of the 150 hydro generators it owns.

[20] One of the dozen Doble clients' specifications considered replacement of this feature. Most do not discuss the subject, so the existing bar is to be reused as is, if there is no uprating.

[21] Only two of the dozen Doble clients' specifications include discussion of these CTs.

[22] Three of the dozen Doble clients' specifications require new surge rings. One requires that they be insulated to Class "F" unless they are made of fiberglass.

[23] Only one Doble client specifies a minimum spacing, 0.4 inches (10.16 mm).

[24] No Doble clients specify a minimum but 0.5 inches (12.7 mm) would be reasonable.

[25] At least 8 of the 12 Doble clients' specifications require Class F insulating materials or better in the winding. Several leave the option B or F, and 2 require Class B or better.

[26] Of the dozen Doble clients' specifications, most allowed either vacuum-pressure-impregnation or "B"-staged processes. However, one client allows only "B"-staged and another client prefers vacuum-pressure-impregnation.

[27] To aid in the installation of coils in small diameter cores, one Doble client has the following option:

> As an alternative insulation system for small diameter cores the coils may be furnished with a ground wall insulation system on the end turns that is different from the system applied to the coil sides, provided that the end turn system is approved by the Contracting Officer. The purpose of this alternative is to allow the ground insulation on the end turns to be slightly more flexible than the coil side insulation.The tape on the end turns shall be essentially the same as that applied to the coil sides; however, the epoxy or polyester resin in the end turn portion may be more resilient than that used in the coil side system; provided that the two systems are completely compatible and form a solid, continuous bond joint; provided further, that the joint between the end turn system and the coil side is located outside of the stator core and not in a bend in the coil. The Contractor shall submit service records test data for identically constructed coils as requested by the Contracting Officer for the purpose of evaluation and approving the overall insulation system.

[28] This requirement is specified by only one of the Doble clients.

[29] Only one Doble client specifies this requirement.

[30] For ease of installation and repair, single-turn half-coils, or Roebel bars, are generally preferred if they are compatible with the present number of slots and the capabilities of the excitation system.

[31] A few clients' specifications limit the spacing to 0.4 inches (10.16 mm) and one to 0.75 inches (19.05 mm). The stator slot and winding configuration may determine the actual spacing. The real intent is to have a uniform spacing.

[32] One client had this coil edge requirement, one required a minimum radius of 0.093 inches (2.3622 mm). Even the 1/32-inch (0.79-mm) radius is very small and might cause some tearing of the mica tape where bent so tightly.

[33] One client included this requirement. This is a commonly accepted minimum electrical stress, although many European manufacturers claim that a higher electrical stress is possible. By specifying a minimum, the Owner limits the manufacturer's design possibilities particularly with respect to the amount of copper that can be incorporated.

[34] Generally used in very small machines.

[35] Two of the clients' specifications have this requirement for wedge material. Two more require G-10 material only

and another two clients require G-11 material only. One requires NEMA class GPO-1 or GPO-2.

[36] Required by at least two Doble clients.

[37] Three Doble clients specify a wedge locking system.

[38] One client requires five gauging holes in the wedges with holes.

[39] Five of the Doble clients' specifications require that the filler strip material be semiconducting. Others' specifications require semiconducting coating on the coil walls, implying semiconducting filler strips should be used to ensure corona protection in the slot portion. One client requires NEMA GPO-3 materials.

[40] Two of the Doble clients specify minimum filler strip thickness. One has 1/32 inch (0.79 mm) for back strip minimum thickness and 1/16 inch (1.59 mm) for front strip minimum thickness. This client also requires ripple side filler strip. The ripple side filler strip should be installed on the unloaded side of the coil. The other client specifies 0.032-inch (0.813 mm) minimum for the front filler strip. One client requires that "Not more than two top filler strips may be combined to provide the proper thickness. Top fillers shall be cemented together every 18 inches (45.72 cm) and within 3 inches (76.20 mm) of the end of the core."

[41] Two of the Doble clients' specifications have these requirements for spring compression. One client requires compression of 70% minimum and 90% maximum spring compression. One client requires that the ripple spring fillers be 0.035 inches (0.889 mm) thick with a peak-to-peak ripple of 0.105 inches (2.667 mm).

[42] Few of Doble clients' specifications discuss ring buses and of those that do, there is little agreement on method of construction. One specifies that "Any joints made for easy assembly/disassembly shall be silver plated with bolts of similar coefficients of expansion and provide and average retained clamping force of 6000psi (41.37 MPa) over the entire joint." If joints are desired for ease of disassembly, the spec should indicate so and this requirement should be included.

[43] One Doble client's specifications requires Class "B" or better and one requires the same insulation system as the winding. Manufacturers have generally standardized on Class "F" or better insulation.

[44] Required in only one Doble client's specifications.

[45] One Doble client has this requirement for a dummy core to check fit and uniformity of production coils.

[46] Twelve or 18 for smaller stators.

[47] Eight of the 12 Doble Client specifications require 10 ohms @ 25°C copper RTDs. One requires 100 ohms @ 0°C platinum RTDs, one requires 10 ohms @ 25°C dual element RTDs, and one requires 10 ohms @ 25°C/100 ohms @ 0°C dual element RTDs. Two of the specifications state the coefficient of resistance that describes copper rather than actually requiring copper elements: The detectors shall have a temperature coefficient of resistance of between 0.003830 and 0.003890 at 25°C and as otherwise specified in paragraph 4.5 of IEEE119.

[48] One Doble Client has more specific RTD location requirements: The detectors shall be evenly spaced around the unit, six in each phase–two located in the top third of the slot, two located in the middle third of the slot, and two located in the bottom third of the slot.

[49] One Doble client specifies that the portion of the RTD within the slot be coated with a semiconducting paint before installation.

[50] One Doble client has this optional test described in the specifications.

[51] Choose either this or the next paragraph, as applicable.

[52] Three of the 12 Doble clients' specifications offered have requirements for removal and installation of the winding. One has a requirement that a Contractor's (manufacturer's) erection engineer assist the Owner in the disassembly and installation of the winding. Two require that the Contractor remove the existing winding and install the new winding. If the Owner is to remove the winding, use this paragraph. If the Contractor is to remove the winging, use the next paragraph instead. Depending on who is to dispose of the winding, choose either of the two following paragraphs.

[53] Choose either this or the previous paragraph, as applicable. If this paragraph is chosen, choose also one of the next two paragraphs.

[54] Include if repair to stator iron is anticipated and if sufficient spare stator iron laminations are available.

[55] Other Doble clients require heavy-duty alkyd enamel light grey in color, Fuller O-Brien No.312-XX or equivalent.

[56] The Doble clients' specification indicates that "Waste containing 5 ppm or more is classified as hazardous and must be handled and disposed of as such." Include this if it is still the correct concentration.

[57] Of the 10 Doble clients' specifications requiring strand testing, two require a voltage above 50 volts ac, 3 require a voltage above 60 volts ac, one requires a voltage above 100 volts ac, 2 require a voltage above 120 volts ac, and one requires 500 volts dc.

[58] Three Doble clients listed the test voltage as 43 kV, or 1.5(2e + 1 kV) for a 13.8kV machine. One requires 1.4(2e + 1 kV), which would be 40kV for a 13.8 kV machine. One requires 40 kV for a 13.8 kV machine. One requires 39 kV for a 13.8 kV machine. One requires 1.3(2e + 1 kV), which would be 37 kV for a 13.8 kV machine. One requires either 36kVac or 61 kVdc for a 13.2 kV machine. One requires 2e + 4 kV after assembly and 2e + 1 kV before shipment. And one requires 2e + 1kV.

[59] One Doble client specifies a 15 kV peak voltage and one specifies a 19.5 kV peak voltage for a 13.8 kV machine. One client requires a pulse with a rise time between 0.1 and 0.2. One client determines that a 10% deviation in wave form constitutes a failed coil.

[60] Two of the Doble clients specify that the voltages, for a 13.8kV machine, be 2 kV and 8 kV. Two specify 2 kV and 12 kV for 20 kV machines. One specifies 2 kV and line to ground voltage. Two specify 1/4 and 1times the line to ground voltage. One specifies that the values be computed on the basis of 15 and 60 volts per mill of estimated ground wall insulation. One specifies 0.2 and 1.0times the line to ground voltage.

[61] Two Doble clients fail the coil if the tip-up is greater than 0.5%, one client fails the coils if any have tip-up greater than 0.6% and 95% of the bars must have tip-up less than 0.5%. One client considers the coil failed if its tip-up exceeds 0.4% or if the numerical difference of 90% of the coils are greater than 30%. One rejects the coils if more than 90% of the coils have a tip-up greater than 0.9%. One client rejects if the dissipation factor at 25% exceeds 2.25%.

[62] Two Doble clients specified dissipation factor testing. One had these acceptance criteria, one required that "the dissipation factor at 25% shall not exceed 2.25% for acceptable coils."

[63] One Doble client specifies this test.

[64] Required by one Doble client.

[65] Two Doble clients specify this test.

[66] Two Doble clients' specifications require this test. Only one states the voltage.

[67] Two Doble clients specify this test.

[68] One Doble client requires this test.

[69] Eight of the 12 Doble clients require some endurance testing on the coils.

[70] Of the eight Doble clients specifying endurance testing, six require testing of prototype coils in addition to testing of production coils.

[71] Four Doble clients require 4 prototype coils (or sets of bars), one requires 10 prototype coils, and one requires 3 prototype coils.

[72] Two of the eight Doble clients that require endurance testing require that the Contractor perform the testing, three have an independent testing facility perform the testing, and three perform testing at their own facilities.

[73] This pre-test dissection was required only by the Doble client that required 10 prototype coils.

[74] For a 13.8 kV machine.

[75] Prototype dimension checks were specified only by the Doble client that required a dummy core.

[76] Several Doble clients consider failure to be when one coil fails before 400 hours has passed.

[77] Four Doble clients require this prototype test.

[78] Two Doble clients require this test. There are no pass/fail criteria.

[79] Most of the prototype testing requirements require that all 4 coils be thermal cycle tested after the previous tests are performed. Where 10 prototype coils are required, 5 are required to be thermal cycled without having had the other tests performed in advanced.

[80] 200 cycles is the most common, 250 the next most common number.

[81] 155°C is the most common high temperature. One Doble client requires 150°C.

[82] ...or "at an average rate of rise of 2.5°C/minute (+/- 1°C/minute) and then cooled down to 40°C at a similar rate."

[83] Of the eight Doble clients that specify accelerated life testing, three require prototype testing only, two require production coil testing only, and three require both prototype and production coil testing. The requirements for the specific production tests are similar or identical to the tests for prototype coils.

[84] See "Sixty-Second Annual International Conference of Doble Clients, Paper 7H" for more information on core repair.

[85] Listed by one Doble client.

[86] Five of the 12 Doble clients' specifications list requirements for a test to determine the condition of the existing core. Three of the specifications require a loop test with requirements like those in this paragraph. Two of the specifications require an EL-CID test, with requirements like those in the next paragraphs. Choose one or the other.

[87] Most Doble clients and machine manufacturers consider a 5°C or greater difference in temperature to be a "hot spot" in need of repair. One Doble client, who requires the EL-CID test, has indicated the hot spot temperature as anything more than 2°C. The EL-CID test requirements follow this paragraph.

[88] Most Doble clients and machine manufacturers consider differences in core steel temperatures of 6°C or greater to be "hot spots." One Doble client specifies a temperature of 2°C or greater to be a hot spot in need of repair.

[89] Four Doble clients require daily field testing.

[90] Two Doble clients require field testing daily or once per work shift.

[91] Four Doble clients require this test voltage and one requires 54 kVdc for a 13.8 kV machine. One requires 60 kVdc twice per day on the new coils installed and 53 kVdc after all coils are wedged in place.

[92] One Doble client has the following requirement.

[93] Two Doble clients require this test if form wound coils are installed.

[94] One Doble client specified a 10,000 volts peak surge test for a 13.8 kV machine.

[95] Two Doble clients include this requirement.

[96] One Doble client has this requirement.

[97] One D client requires 1500 Vac for one minute and 1000 Vac one minute with minimum resistance to ground of 5 megohms.

[98] This requirement is intended for turbogenerators and hydrogenerators more than 600 MW.

[99] Required in one specification.

[100] Most Doble clients requiring installation by the Contractor require this test at this voltage. One requires the dc high-potential test in addition at 40 kVdc for a 13.8 kV machine and one requires only the dc high-potential test at 48.6 kVdc in accordance with ANSI C50.12.

[101] Generally accepted voltage among four Doble clients with this provision. Some increase voltage in steps, some ramp smoothly at a preset rate.

[102] One Doble client requires this test.

[103] 13.8 kV machine.

[104] I think this is an excellent test that could prevent corona damage and allow convenient remediation before the rotor is in place. However, I suggest that the three phases be excited separately.

[105] Most of the following tests apply to uprated generators or machines that have had significant modifications to the core, poles, or excitation.

[106] Some Doble clients require this testing on all machines, some on only one.

[107] If more than one winding is furnished, heat run tests may be beneficial for each unit.

[108] The loss test is normally not performed for a rewind. However, if a loss test was not part of the original

acceptance tests, or if there are changes in the winding rating or a configuration that would make knowledge of the losses desirable, the test should be considered. If the test is included, add the appropriate requirements in the "Warranted Characteristics" and "Failure to Meet Performance Warranties" clauses and "Work and Materials to be Furnished by the Owner" paragraph.

[109] These tests should be required only when the machine is uprated or when poles, excitation, or stator core are modified or changed.

[110] The Doble clients that require five-year warranty periods have three inspections at 1, 2 1/2, and 5 years. Clients with shorter warranty periods have fewer inspections. Inspections generally are made when unit is available and may not exactly meet schedule.

[111] If no prototype testing is required.

[112] When multiple units are ordered, the installation times are generally oneyear apart. It generally takes about 180 days to manufacture windings for a moderately sized (140MW) machine. Core lamination manufacturing can be done concurrently.

[113] If prototype testing is intended.

[114] One Doble client indicates 155days for a 20,000hp, 13.8 kV machine.

[115] One Doble client indicates 40days.

[116] One Doble client indicates 225days for a 20,000 hp machine.

[117] One Doble client indicates 40days to test.

[118] One Doble client indicates 275days for a 20,000 hp machine.

[119] Include if the existing winding(s) is expected to fail soon.

[120] Include if failure is imminent.

[121] This penalty must be determined by how much power generation is lost and what water delivery considerations govern. One Doble client lists $1,000 per day, one lists $750 per day, one lists $2,000, one lists $3,000, and one lists a current specification as $23,000.

[122] Generally the same principle as liquidated damages listed for the blank above.

[123] If Contractor is to remove winding.

[124] One Doble client requires a five-year warranty on design, parts, and labor. One requires a five-year design warranty, three years after shipment (for installation by Owner), and twoyears of operation. Two Doble clients require a 24-month warranty. The manufacturers report that they don't put any more quality into the materials or installation, they just gamble or add more money to the bid price as insurance. Another Doble client specifies a one-year warranty.

[125] One Doble client uses the following formula to determine the kW penalty:

$/kW = (8750)(PF)(EC)(PWF)

Where

PF = Plant factor
CC = Capacity charge
EC = Energy value

$$PWF = \frac{(1+i)^n - 1}{i(1+I)^n}$$

I = interest rate/year
n = number of years of life of machine (25)

Another Doble client uses the following:

$3.50 for each watt of loss caused by the stator winding resistance exceeding the value specified.

The incremental stator resistance R, is the difference between the guaranteed value of winging resistance, R_g, and the sum of the measured coil resistances, R_m, for each phase. The value of R, in ohms, shall be determined from the following formula:

$R = (48 \times R_m) - R_g$

where R_m is the resistance value per coil, in ohms; determined by testing, and corrected to 75°C and R_g = _____ ohm. Therefore, the total value of decrease (D), in dollars, is D = $3.50 x 3 x^2 k R.

[126] One Doble client uses this paragraph and the following calculation to determine the failure to meet warranted capacity:

$/0.01% = (0.0001)(Warranted kW)(CC)(PWF)
= $xxx for each 0.01% actual capacity is less than warranted.

Where

PF = Plant Factor
CC = Capacity charge

$$PWF = \frac{(1+i)^n - 1}{i(1+i)^n}$$

i = interest rate/year
n = number of years of life of machine (25)

Another Doble client uses this paragraph instead:

If the results of the heat run test indicate that the replacement winding has a temperature rise larger than specified when operating at the new (guaranteed kVA rating, rated power factor, and rated kV, the Contractor will be assessed a liquidated damage amount, that shall not be considered a penalty, at the following rate:

(new kVA rating - actual kVA rating @ rated temp)(price winding and labor) x 10

$$\text{Damages in dollars} = \frac{\text{---------- (illegible) ----------}}{\text{new kVA rating}}$$

The kVA rating at rated temperature rise would be determined by test. A deviation of plus °C rise at the new guaranteed kVA rating will be allowed to compensate for possible instrumentation error.

[127] One Doble client has this limit on damages.

C
ELECTRICAL EQUIPMENT SUPPLIERS

The global marketplace for the supply of electromechanical equipment is complex and ever changing. Recommended sources of up-to-date information regarding the suppliers and goods and services connected with hydromechanical equipment include:

- *Hydro Review Industry Sourcebook* published yearly by HCI Publications, 410 Archibald Street, Kansas City, MO 64111-3046, USA
- *International Water Power and Dam Construction* Yearbook published yearly by Wilmington Business Publishing, Wilmington House, Church Hill, Wilmington, Dartford, Kent DA2 7EF, UK

Over time, with mergers and acquisitions in the industry, it has become, in some cases, difficult to identify the current Original Equipment Manufacturer (OEM) for a particular brand of generator. This list of generator manufacturers, while not exhaustive, assists with the identification process. Colloquial names have been used in lieu of formal company names for ease of identification.

Generator Brand Name	Manufacturer to Contact
ABB	Alstom
AEG	AEG
Allis-Chalmers	Voith Siemens Hydro
Ansaldo	Ansaldo Energia
ASEA	Alstom
BHEL	Bharat Heavy Electrical (BHEL)
Brown Boveri	Alstom
Dongfang	Dongfang
Electrosila	Energomachexport (Electrosila)
Elin	VATech
Energoproject	Energoproject
English Electric	GEC (U.K.); Alstom
Fuji	Fuji
General Electric	General Electric (GE)
Harbin	Harbin Power Equipment
Hitachi	Hitachi
Ideal Electric	Ideal Electric
IMPSA	IMPSA
MG Electric	Schneider

Electrical Equipment Suppliers

Generator Brand Name	Manufacturer to Contact
Mitsubishi	Mitsubishi
Pauwels	Pauwels
Siemens	Voith Siemens Hydro
Toshiba	Toshiba
Wabash	Wabash Power Equipment
Westinghouse	Voith Siemens Hydro

High-voltage stator windings for generators are supplied by the following firms in North America:

- Voith Siemens Hydro
- GE Hydro
- Alstom
- Eastern Electric
- National Electric Coil

Large firms also manufacture windings in Europe, Russia, South America, India, and China, and include:

- Siemens
- VATech
- ABB
- Ansaldo
- Electrosila

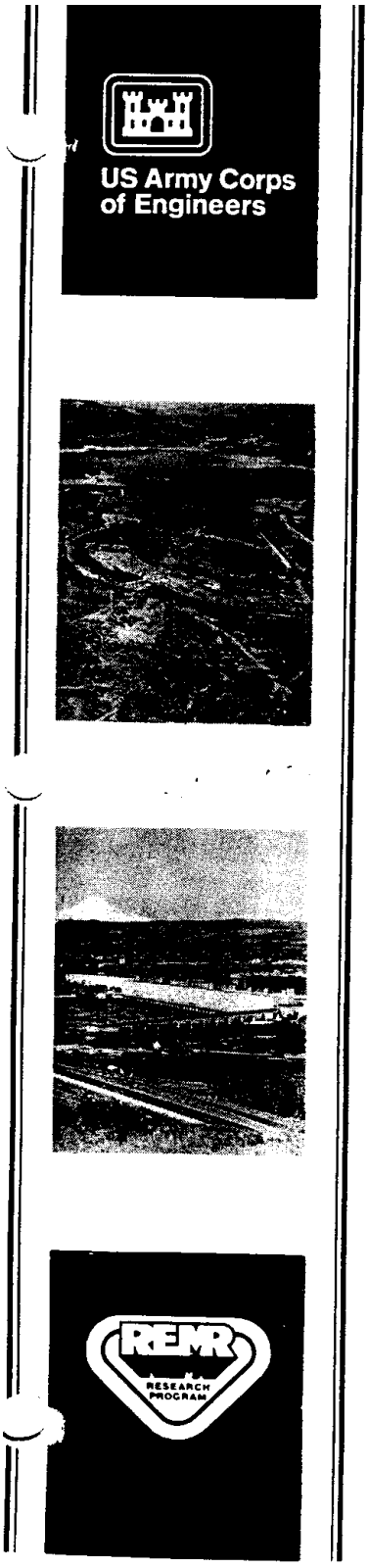
There are also a number of smaller specialty companies that supply small, lower-voltage windings for generators to national markets. More information on these companies can be obtained from the sources listed above.

D
REPAIR, EVALUATION, MAINTENANCE, AND REHABILITATION CONDITION ASSESSMENT PROCEDURES

This appendix includes reproductions of the appropriate sections of the U.S. Army Corps of Engineers (USACE) Condition Rating Procedures/Condition Indicator for Hydropower Equipment for equipment covered in this volume. The document was produced by the USACE as part of the Repair, Evaluation, Maintenance, and Rehabilitation (REMR) research program.

As described in Section 4.4.1, these condition rating procedures are provided as an example of a condition rating procedure. The USACE intends to review the procedures commencing in 2000.

Our thanks to Messrs. Jim Norlin, Paul Willis, and Craig Chapman of the USACE in ensuring that the REMR procedures are reproduced here.



REPAIR, EVALUATION, MAINTENANCE, AND REHABILITATION RESEARCH PROGRAM

REMR MANAGEMENT SYSTEMS–HYDROPOWER FACILITIES

CONDITION RATING PROCEDURES/ CONDITION INDICATOR FOR HYDROPOWER EQUIPMENT

by
Department of the Army
Hydroelectric Design Center
North Pacific Division
Corps of Engineers
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	Problem Area		Problem Area
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HY	Hydraulics	OM	Operations Management
CO	Coastal		

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COVER PHOTOS:

TOP - Lost Creek Flood Control/Hydropower Project, Rogue River, Oregon.

BOTTOM - The Dalles Navigation/Hydropower Project, Columbia River, Oregon.

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The Hydropower Condition Indicator Manual is a maintenance management tool for condition assessment and evaluation of electrical and mechanical equipment in hydroelectric powerhouses.

Data on various pieces of hydropower equipment is gathered by field inspection and testing. Uniform procedures are applied to evaluate the data and assign a Condition Index (CI) to the equipment. The CI indicates the condition of the equipment. The CI thus affords a means for the uniform and quantitative comparison of the condition of equipment to that in another.

The collected data will eventually yield curves documenting the deterioration of equipment based upon age and usage. Such curves can be used to predict future condition so that maintenance managers can optimally prioritize and budget maintenance and rehabilitation money.

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PREFACE

The study reported herein was authorized by Headquarters, US Army Corps of Engineers (HQUSACE), as part of the Operations Management problem area of the Repair, Evaluation, Maintenance, and Rehabilitation (REMR) Research Program. The work was performed under Civil Works Research Work Unit 32672, "Development of Uniform Evaluation Procedures and Condition Index for Civil Works Structures," for which Dr. Anthony M. Kao (CECER-FMM) is the Principal Investigator. Mr. James A. Norlin **(CENPD-PE-HD),** Hydroelectric Design Center (HDC). is the Principal Investigator and Mr. Craig Chapman (CECW-OM) is the Technical Monitor for this study.

Mr. Jesse A. Pfeiffer, Jr. (CERD-C) is the REMR Coordinator at the Director ate of Research and Development, HQUSACE. Mr. James E. Crews (CECW-O) and Dr. Tony Liu (CECW-ED) serve as the REMR Overview Committee; Mr. William F. McCleese (CEWES-SC-A), US Army Engineer Waterways Experiment Station (WES), is the REMR Program Manager. Dr. Anthony M. Kao (CECER-FMM) is the Problem Area Leader for the Operations Management problem area.

This work was conducted by the Hydroelectric Design Center under the general supervision of Glenn R. Meloy, Chief of CENPD-PE-HD.

Acknowledgement is given to the Field Review Group members and to the numerous individuals at many of the Corps' operating projects that have reviewed, tested and commented on the procedures outlined in this manual. Their input has been invaluable in the acceptance and usability of this document.

COL Daniel Waldo, Jr., is Commander and Director of USACERL, and Dr. L.R. Shaffer is Technical Director.

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PART I: INTRODUCTION

1-1. The Corps of Engineers owns and operates 76 hydroelectric powerhouses located throughout the United States. These powerhouses have a combined total capacity of nearly 21,000 megawatts, making the Corps the largest single operator of hydroelectric facilities in the United States.

The Corps' system of hydropower projects is unique and significantly different than other large producers of hydropower in several ways. We do not supply power to a single system, but rather to many large and small power distribution systems throughout the country. We are involved only with hydropower and power production, and have no direct involvement in power distribution or sales. Our funding for repair and replacement of equipment is appropriated by congress, and not derived from power sales.

Planning for major repairs or replacement of hydropower equipment presents some unique difficulties to the Corps. Funds are provided as a part of the overall Operation and Maintenance budget for the Corps. The funding is thus intermingled with funds for dredging, navigation, flood control, recreation and most other aspects of the Corps' involvement with civil works activities. The funding requirements for the O&M of hydropower facilities is a relatively small portion (5-6%) of the overall Corps of Engineers O&M budget.

The cost of routine operation and maintenance activities can be programmed relatively easily based upon historical efforts. The non-routine effort is much more difficult to forecast. This program is a key step in the development of a reliability centered maintenance program. This program will provide comprehensive projections of the need for and benefits derived from specific, non-routine maintenance work.

Concept

1-2. The Hydropower Equipment Condition Indicators Program is being developed at the direction of HQUSACE as a part of the Operations Management Problem Area of the Repair, Evaluation, Maintenance and Rehabilitation Research Program (REMR). REMR Management Systems are designed to be decision support tools for determining when, where, and how to effectively allocate maintenance and rehabilitation dollars for Civil Works facilities. These systems are being developed to provide:

a. Objective condition assessment procedures.

a. Means for comparing the condition of facilities and tracking change over time.
b. Procedures for life-cycle cost analysis of different maintenance policies and rehabilitation alternatives.
c. Computer software for storing and organizing data, performing calculations, and producing a variety of reports.

There are many independent factors that must be considered as key elements of an overall maintenance management program. The items in the following list are all pertinent, but the list is not necessarily all inclusive.

1 - Policy / Planning / Mission

2 - Condition / Function / History/Performance

3 - Importance of facility

4 - Economic Analysis

5 - Risk / Consequences of failure

6 - Repair lead time

7 - Budget / Current - Future

8 - User Cost

9 - Return on Investment

10 - Resource availability

11 - Future performance

One of the primary goals of the REMR Operations Management System is to take all of these factors and place them into a single, large computer program that will be used as a management tool. It is anticipated that the final product could take as much as 10-20 years to fully develop, test, refine and implement. A program of this nature must be developed one step at a time.

The chosen starting place is the technical area. This is item 2 on the list above. Factors that can be considered relevant to the Condition / Function / History/ Performance of a piece of hydropower equipment are as follows:

1 - Current Condition

2 - Current Performance

3 - Past Condition and Performance (History)

4 - Future Condition and Performance (Estimate or prediction)

5 - Trends

6 - Equal comparison of facilities condition / performance

7 - Definition of required function

The items on this list can be separated into two general categories, equipment condition and performance of function.

The current program is limited to looking at the category of equipment condition only. The performance of function factors will be considered at a later time.

The initial step in determining the current condition of a piece of equipment is to establish a standard definition of condition. This has already been established as the REMR Condition Index scale. This scale is numerically based, extending from 0 to 100, without units. REMR Technical Note OM-CI-2 which further defines and explains the condition index scale is included in this report as Appendix A.

The second step is to develop a standard method of measurement of condition. A standard indicator is something that is specifically definable, and repeatable. An example of definable and repeatable is the measurement of "volts". There is a specific definition for "volts", and calibrated test instruments for measuring voltage. As a result, there is no confusion or misunderstanding when someone says that a particular piece of equipment is designed to operate at 110 volts AC, for example. The indicators and methods used to define the condition of equipment should strive to be equally as well defined and repeatable. The point being that when two project engineers on opposite sides of the country each say their turbines have "bad cavitation damage", the actual extent of damage to each turbine is comparable.

Generally speaking, Condition Indicators are either test results from standard tests, or visual or other non-destructive examinations that give an indication of the current condition of a piece of equipment. Factors such as usage, history of maintenance, availability of parts and economic

factors are not to be considered when defining current condition. These are important elements, but they will be considered elsewhere in the overall REMR Operations Management System.

The Condition Index, by definition, is a snapshot look at the absolute condition of a facility or piece of equipment. Time, age and money related factors are not included in the development of this index. It is a standardized evaluation of the condition of the equipment based strictly upon test results and inspection by visual or other means. The condition index algorithm should allow for the additional *condition information* that is available from a detailed inspection if the equipment is partially or totally dismantled for other reasons, but should not require this type of inspection.

Just as a chain is only as strong as the weakest link, the current condition of most pieces of hydropower equipment is only as good as the poorest indicator. This method of overall evaluation allows for an easy method of determining the work necessary to improve the condition and the extent of overall improvement. An exception to this general rule is made when several different tests or inspections are used for evaluating the same thing. The best example of this is the myriad of tests used to evaluate the condition of generator stator winding insulation.

Snapshots of the equipment condition can be taken at regular or irregular intervals. Regular intervals would normally include two separate condition evaluations at each major maintenance interval (for example -quadrennial). The initial evaluation would reflect the condition of the equipment as it was removed from service for maintenance. The second evaluation should reflect the improvement in condition as a result of maintenance procedures. For example, during a turbine overhaul, normal maintenance procedures call for weld repair of areas damaged by cavitation. The two evaluations of condition should accurately reflect the improvement in the condition of the turbine as a result of these weld repairs.

Other measurements that will affect how well equipment can be expected to survive, such as hours of usage, severity of usage and levels of routine maintenance will be used to predict the future rate of condition index deterioration. This will be developed during a later phase of the overall REMR Operations Management System.

Limitations

1-3. Condition indices are a tool to help estimate the remaining service life of equipment. Service life, however, is not necessarily the same as useful life. Powerhouse Automation Systems, for example, are most often replaced for reasons other than condition.

Example

1-4. The example used to demonstrate how Conditions Indicators for mechanical and electrical equipment are used, is something that everyone is familiar with, an automobile. The condition of a specific automobile is something that can be determined by an automotive diagnostic center. Through testing and inspection, they can evaluate the condition of the vehicle and provide a detailed listing of the items that are not properly operational.

However, the diagnostic center cannot provide all of the information that is necessary to determine the extent of repairs that should be performed, or if the vehicle should be replaced. Economics obviously will play a major part of this decision. The functionality of the vehicle for the purpose it is needed also plays a part. You wouldn't buy a two seat sports car if you need to

transport 4 people and their luggage on a regular basis. Finally, the diagnostic center cannot predict how long it will be before the vehicle sustains a major failure.

We need to eliminate factors that are not relevant to condition before proceeding to those factors that are relevant. The age of the automobile is the first factor to eliminate. Assume that the theoretical design life for an automobile is 15 years. Many cars will last well past that age, but a great number will see a wrecking yard as a result of mechanical failure much sooner. However, the condition of a vehicle is not dependent upon its age. Consider all of the collector cars that are in better condition now than they were when they were new. Likewise, consider the new car that has a transmission failure in the first 10 miles because a mechanic forgot to put oil in the gearbox.

It is therefore easy to eliminate age as being irrelevant to condition.

The next factor to eliminate is usage. The diagnostic center cannot tell what use or abuse a car has seen. Three similar cars, each with 99,000 miles on the odometer may each have seen dramatically different service. One may be all stop and go city miles, another highway miles and the third may actually have 299,000 miles on the odometer.

Thus, we also eliminate operational history or usage.

Maintenance history can also be eliminated. The diagnostic center does not have access to the maintenance records, nor are they familiar with the skills of the mechanic. However, they can get a good indication of the level of maintenance from visual inspection. Rusty body panels along with tape and bailing wire repairs are very obvious. This would indicate a car in much poorer condition than another vehicle with a freshly waxed paint job and all bolts where they belong.

Maintenance history is eliminated, but a thorough visual inspection is included.

The diagnostic center, in addition to completing a thorough visual examination, will perform many different types of tests. These tests will check out the various electrical and mechanical systems of the vehicle. A compression test combined with a leak-down test and an examination of the lubricating oil will give a relatively good indication of the mechanical condition of the engine. These tests can be run on virtually all cars. Tests on other systems may vary depending upon the vehicle. For example consider the fuel supply system. There are carburetors, mechanical fuel injection systems, electronic fuel injection systems and turbocharged versions of each. They all perform the same function in a different manner. Certain tests, such as an exhaust gas analysis, can be used to get a very basic indication of the condition of any of these systems. Other, more specialized tests are relevant to only one type of system. However, these tests can give a better indication of condition.

We have included only these basic tests for most of the items of hydropower equipment. In many cases, more detailed tests could be run, but the value of performing them on a routine basis is questionable.

Categories of Equipment

1-5 The following categories of hydropower equipment are included as part of this program:

ELECTRICAL

Hydrogenerator Stators
Excitation Systems
Circuit Breakers
Main Power Transformers
Powerhouse Automation Systems

MECHANICAL

Turbines
Thrust Bearings
Intake Valves
Governor System
Cranes & Wire Rope Gate Hoists
Hydraulic Actuator Systems

STRUCTURAL

Emergency Closure Gates
Power Penstocks

PART II: HYDROGENERATOR STATOR

Program, Format and Method

Explanation of Program

2-1. The overall stator index rating is a number between 0 and 100 which will be used to define the present condition of the stator. The number will be used in the REMR Condition Index Scale which is shown below.

The overall condition index is determined from a series of tests and inspections, which are discussed later in this section. The criteria behind these inspections and tests are such that they may be performed during an annual maintenance period (generally 1-2 weeks).

While these inspections and tests may be performed with the rotor in place, in most cases, having the rotor removed would provide an easier environment for unit inspection and testing.

Condition Index Scale

Value	Condition Description	
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate.
25.-39	Poor	Serious deterioration in at least some portions of equipment. Function is inadequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure D-1

With the rotor still in place, the core may still be inspected by removing one or more pole pieces, and the unit rotated by hand. With the rotor in place and depending on the architecture of the machine, inspection of the bottom and top of the generator might be done in confined spaces. This may make inspection difficult. Ozone detection should be performed prior to removing the unit from service. The following tests, inspections, and procedures are a major cross section of what industry presently examines to determine stator condition:

1. Blackout Test

2. Corona Probe Test

3. DC High Potential Test

4. Insulation Resistance Test
5. Ozone Detection Test
6. Partial Discharge Analysis Test
7. Circuit Ring Inspection
8. Core Inspection
9. Endturn Inspection
10. Lead Inspection
11. Slot Inspection
12. Wedge System Inspection
13. Reduced Ratings Due to Known Failures

The performance and description of these condition indicators are covered in Technical Report REMR-EM-4 "HYDROELECTRIC GENERATOR AND GENERATOR-MOTOR INSULATION TESTS". Specific test procedures and descriptions will not be covered in this Condition Indices Program. It is assumed that individuals performing the tests to determine a condition number have performed these tests previously, and have had experience in the testing and inspection of hydrogenerators. Only experienced personnel should attempt to perform these tests since many of these tests require that the unit be energized.

Conditions such as obsolescence, lack of features, and lack of spare parts are not discussed in this section since these have nothing to. do with the present condition of the unit. Tests and interpretation of results must be done in conjunction with the analysis and comparison of previously obtained test results. This is required to determine trending and possible equipment changes. Condition assessments may be made with comparison to previous test results for specific tests. This is called trending. Examples of this are corona probe and partial discharge analysis results. Since trending is necessary to determine present generator condition, accurate record keeping is an absolute requirement in a successful Condition Indices Program. In addition to the written records required for trending, records such as photos, and in 8ome cases, a video of the area of concern, along with a narrative of the items which are of concern may be included.

When a unit is new and has met all guaranteed requirements of the original contract and has very few operating hours, it may be assumed that the unit is operating at its peak condition. At this point, it is therefore assumed that if any one of the tests were conducted, that the result of the test would be a condition of 100. As a unit ages, or logs additional operating hours, then this condition will drop from the as-new condition of 100 to a lower value.

Individual tests and inspections may not have the same importance or weight as other tests. The overall condition index value will be determined from the lowest individual condition index. If

no previous test data is available, or the test shown is not done, then the condition for that individual test should be 100.

Explanation of Format

2-2. The formats used to discuss the various tests and inspections for obtaining the condition numbers for a generator are similar. The first section is an introduction which describes the test or inspection. The second section gives instructions on how to perform the test or inspection. The third section explains how to perform the evaluation of the data and how to fill out the appropriate part of the Data Evaluation Sheet. The final section gives the recommended frequency of performing the test or inspection.

Explanation of Method

2-3. A condition number between 0 and 100 is determined for each condition indicator based on the results of tests and inspections. The overall condition index rating for the generator is the lowest value of any of the condition numbers.

Overall Stator Condition

Introduction

2-4. The overall stator condition is calculated using the following condition indicators:

1. Blackout Test
2. Corona Probe Test
3. DC High Potential Test
4. Insulation Resistance Test
5. Ozone Detection Test
6. Partial Discharge Analysis Test
7. Circuit Ring Inspection
8. Core Inspection
9. Endturn Inspection
10. Lead Inspection
11. Slot Inspection
12. Wedge System Inspection
13. Reduced Ratings Due to Known Failures

Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various tests and inspections which are discussed later.

Filling Out Data Evaluation Sheet

2-5. Column 1 lists the thirteen condition indicators which are used for generator evaluation. Others may be added in the future. Fill in the date the test or inspection was made in column 2. Insert any notes or remarks about the condition number in column 3. For instance, if the condition number is low, put in the reason for it being low. Put the condition number for the particular condition indicator in column 4.

The overall stator condition index rating is the lowest of the individual condition indicator numbers. This rating is placed in the box in the lower right corner of the Overall Stator Condition Data Evaluation Sheet.

A sample of this form is shown on page 2-6. Information to be completed by the field is shown in script text. Blank data collection sheets are included at the end of this document. Sample data collection sheets will be included in the next update of this manual.

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Reduced Ratings Due to Known Failures

Project: *Old Hydro Plant* Unit No. *1*
Manufacturer: *GE*
Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Blackout Test	*7/3/90*	*Corona activity seen in 52 slots -> 52/560 = 9.3%*	*87*
Corona Probe Test	*7/3/90*	*Readings average 10% higher than original readings*	*90*
DC High Potential Test	*7/3/90*	*Ramp test predicted a failure voltage of 37 kV*	*58*
Insulation Resistance	*7/3/90*	*Megohm reading = 490*	*62*
Ozone Detection Test	*7/3/90*	*Ozone concentration = 1.5ppm*	*65*
Partial Discharge Analysis Test	*7/3/90*	*Partial discharge reading of 90 NQN*	*84*
Circuit Ring Inspection	*7/3/90*	*Discoloration, sponginess, wear due to movement. Surface area = 25%*	*50*
Core Inspection	*7/3/90*	*Stots 16-30 show fretting corrosion -> surface area = 2.7%*	*95*
Endturn Inspection	*7/3/90*	*Discoloration in slots 1 & 2; Total slots = 560 -> 2/560 = 0.9%*	*95*
Lead Inspection	*7/3/90*	*Discoloration, sponginess, wear due to movement. Surface area = 17%*	*65*
Slot Inspection	*7/3/90*	*Loose wedges in slots 16-30 -> 14 slots / 560 = 2.5%*	*95*
Wedge System Inspection	*7/3/90*	*2024 loose wedges. No slots entirely loose. 2024/8960 = 22.6%*	*54*
Reduced Rating	*NA*	*Unit capable off full nameplate rating*	*100*
		Overall Generator Condition Index Rating	*50*

Blackout Test

Introduction

2-6. This evaluation is used to determine the condition of the generator based upon a blackout test. This test may be performed on generators rated 6900 volts and above. The test may be performed with the rotor in place or removed. With the rotor removed, greater detail of discharge in the slot region is available. Typically, the test is done in the evening with the powerhouse lights off. A black plastic covering may be placed over the air housing to help eliminate outside light. All three phases of the stator winding are energized at rated voltage, and observers inside the unit look for evidence of corona. Particular areas of corona are noted, with reference to slot number. Pre-applied glow tape is useful in determining the slot number during the test.

Instructions for Evaluation

2-7. In order for blackout test results to be meaningful, test conditions should be as uniform as possible. Data such as relatively humidity, and the date and time that the test is conducted should be recorded. Discharge activity should be observed. Condition numbers are based on the percentage of slots showing discharge activity. The following general information is considered for the blackout test:

- Specific information regarding the type of discharge and the location should be documented.
- Because the blackout test does not in itself provide definitive results regarding the units condition, the minimum condition number is 25.

Condition numbers for the blackout test fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to observed partial discharge activity of 15% to 0% of the total number of slots. Percentages between these values should use the linear interpolation method.

Moderate: This category provides a condition number between 40 and 69. This corresponds to observed partial discharge activity of 30% to 15% of the total number of slots. Percentages between these values should use the linear interpolation method.

Major: This category provides a condition number between 25 and 39. This corresponds to observed partial discharge activity of 50% to 30% of the total number of slots. Percentages between these values should use the linear interpolation method.

Filling Out Data Evaluation Sheet

2-8. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection.

2-9. A blackout test should be performed during unit overhaul or every 5 years, whichever comes first.

Corona Probe Test

Introduction

2-10. This evaluation is used to determine the condition of the generator based upon corona probe testing. Internal corona activity and slot discharge are measured with the corolla probe. Measurements with the corona probe are made at three locations on each coil, providing an overall picture of the ionization pattern for the entire winding. The pattern is primarily detected in the top conductors within the slots, with sensitivity reduced towards the bottom of the slot. Corona probe testing has been used by many utilities.

This type of testing is most successful when periodic corona probe tests are taken. Bench marks should be taken when the unit is new or newly rewound. With these bench marks, changes in the winding can be tracked, indicating increased activity and possible winding failure.

Instructions for Evaluation

2-11. Corona probe testing may require previously obtained data for comparison in order to be meaningful. Furthermore, it is unlikely that a unit would be removed from service for poor corona probe readings, without data from other tests and inspections to support this decision. Corona probe data may and will vary from unit to unit. Therefore, providing exact figures which can be obtained for a particular unit and particular winding configuration is difficult. The following general information is considered for the corona probe test:

- Specific information regarding specific slots which have unusual readings should be documented.

- Base information from previous corona probe tests should be available for comparison. If a linear interpolation method is specified, use the procedure provided at the end of this section.

- Readings should be recorded for each slot in three places (top, middle, bottom).

- Statistical analysis of the readings should be performed yielding the mean, median and standard deviation.

- The corona inception and extinction voltages should be recorded.

- Because of the general nature of corona probe testing, there will be a minimum condition value of 25.

Condition numbers for the corona probe test fall into the following three categories:

Minor: If the unit has 0 - 15% of the readings outside one standard deviation of the mean reading, the condition number is in the range from 100 to 70. Values falling between these shall be determined through interpolation.

Moderate: If the unit has 15 - 30%, of the readings outside one standard deviation of the mean reading, then the condition number falls in the range of 69 to 40.

Major: If the unit has 30 - 50%, of the readings outside one standard deviation of the mean reading, then the condition number falls in the range of 39 to 25.

Filling Out Data Evaluation Sheet

2-12. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-13. Unit inspection should be performed during unit overhaul or every five years, whichever comes first.

DC High Potential Test

Introduction

2-14. This evaluation is used to determine the condition of the generator based upon DC high potential tests. DC high potential tests are an excellent method to detect insulation strength, particularly in the end turn areas. A dc high potential test can detect the breakdown of insulation, prior to its failure. There are many different methods used to perform this test. A graded time or ramp test is recommended since breakdown voltage can usually be avoided thus protecting the winding. The graded time procedure is covered in IEEE Standard 95.

It is recommended that the same procedure be used each time the test is repeated in order to properly compare results.

Instructions for Evaluation

2-15. When DC high potential tests are performed using the graded time or ramp test procedure, values can be compared to previous values further limiting the risk of failure. The following general information is considered for the DC high potential test:

- Test values for the dc high potential test should be documented. The same value should be used if possible for all tests. This will allow for some comparison between phases and between previously performed tests.
- Condition numbers will be based on the predicted dc breakdown voltage.
- Because of the nature of this test, it has pass or fail results. In some cases, the unit may fail a dc high potential test, but pass an ac high potential test. Because of this, the minimum condition number is 10.

Condition numbers for the dc high potential test fall into the following three categories:

Minor: If the unit passes its dc high potential test and the leakage current versus test voltage curve in a graded time or ramp test predicts breakdown above the twice rated plus 1000 dc equivalent voltage, then the condition number is 100.

Moderate: If the unit passes its dc high potential test and the leakage current versus test voltage curve in the graded time or ramp test predicts failure between the dc equivalent of the ac machine rating and the twice rated plus 1000 dc equivalent voltage, then the condition number

fans in the range of 11 to 99. For a 13.8 kV rated machine, the dc equivalent voltage and the twice rated plus 1000 dc equivalent voltage are 23.46 kV and 48.62 kV respectively.

Percentages between these two values should use the linear interpolation method.

Major: If the unit fails the dc high potential test or the graded time or ramp test predicts failure below the dc equivalent of the ac machine rating, then the condition number is 10.

Filling Out Data Evaluation Sheet

2-16. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-17. A DC high potential test should be performed during unit overhaul or every 5 years, whichever comes first.

Insulation Resistance Test

Introduction

2-18. This evaluation is used to determine the condition of the generator based upon insulation resistance. The insulation resistance test is an excellent method for determining the general condition of an entire winding. It may also be used to determine if an ac high potential test can be safely performed. Conditions which can affect insulation resistance and polarization index readings are moisture within the winding, surface contamination, and the thickness and overall condition of the insulating system. Testing each phase individually gives a comparison between phases and is recommended. 7be values below are based on this test procedure. Testing should be performed per IEEE Standard 43.

Instructions for Evaluation

2-19. The polarization index and insulation resistance tests may need to be performed twice depending on the test-results obtained. A preliminary test should be performed at the time when the unit is taken down for maintenance. If a unit has a great deal of surface moisture, surface contamination or insufficient drying times were allotted following cleaning with solvents, then a poor Insulation resistance reading may result. If this is the case, the winding should be inspected, cleaned and re-tested. The following general information is considered for the insulation resistance test:

- Test values for the dc high potential test should be documented. The same value should be used if possible for all tests. This will allow for some comparison between phases and between previously performed tests.
- Insulation resistance measurements are made at 1 minute and 10 minute intervals to check the polarization index.
- With the decrease of current with time, the insulation resistance measured at the 10 minute time interval will be higher than the I minute time interval. If the insulation is

clean and dry, the insulation resistance will increase for 10 minutes or longer. If the insulation is dirty, a constant value of the insulation resistance will be reached in 1 to 2 minutes. For generators of 13.8 kV operating voltage, the minimum value of insulation resistance allowable before returning the unit back to service is 14.8 megohms, at 40°C for the entire winding (rated kV + 1) for all three phases, or 44.4 megohms for one phase with the other two phases grounded.

Condition numbers for the insulation resistance test fall into the following three categories: (Note that these values are for the insulation resistance at the 10 minute time period, and phases being tested individually)

Minor: This category provides a condition number from 70 to 100. If the insulation resistance is at least 600 megohms, then the condition number should be 70. If the insulation resistance is at a value of 1800 megohms, then the condition number should be 100. Insulation resistance readings between these two values should use the linear interpolation method to determine the condition number.

Moderate: This category provides a condition number from 40 to 69. These values correspond to insulation resistance range of 150 to 600 megohms. Insulation resistance readings between these two values should use the linear interpolation method to determine the condition number.

Major: This category provides a condition number from 10 to 39. These values correspond to insulation resistance range of 45 to 150 megohms. Insulation resistance readings between these two values should use the linear interpolation method to determine the condition number. In cases where the value is below 45 megohms, this category provides a condition number of 0.

Filling Out Data Evaluation Sheet

2-20. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-21. Unit inspection should be performed during unit overhaul or every 5 years, whichever comes first.

Ozone Detection Test

Introduction

2-22. This evaluation is used to determine the condition of the generator based upon the detection of ozone production. One cause of ozone is the deterioration of the interface between the grading coating areas and the semi-conductive coatings in the end turn areas of the windings. If a gap forms between these two areas, then electrical discharges occur across this gap, which causes further eroding around the edges of the coatings. These electrical discharges surface in the form of ozone concentrations within the air housing of the generator. Ozone can be detected through specialized ozone detection apparatus (an ozone sniffer), and it can also take the form of a gray colored dust, forming on the circumference of the bar or coil at the transition of the

grading and semi-conductive areas, just outside the slot portion. Specific areas where corona dusting is seen should be noted with reference to slot number.

Instructions for Evaluation

2-23. Ozone detection tests considered in this section are those which are performed when the unit is running, and taken within the generator barrel. These ozone concentrations considered are air-born particles, with sampling taken through an ozone sniffer. In 1970, the Wilhams-Steiger Occupational Safety and Health Act was passed. It stated that ozone concentrations in the work areas shall be not more than 0.1 parts per million, with out the use of breathing apparatus. High concentrations of ozone are quite unsafe to work in, are damaging to the respiratory system, and are an eye irritant. Besides the obvious health risks, ozone concentrations are a useful tool in detecting the presence of partial discharges. When this occurs, additional test s such as partial discharge analysis, or corona probe can be used to locate areas of concern. The following general information is considered for the ozone detection test:

- New ozone measurements should be taken under the same general conditions as previously taken measurements. The area where the measurement is taken within the machine, as well as generator terminal voltage loading, temperature and relative humidity should be documented.
- If a generator does exhibit high ozone concentrations, it may still be possible to operate it at full capacity. However, this may create unsafe health conditions for plant workers, depending on several factors. Areas to consider are where the generator is located, ventilation, and the need for workers to be in the general location when the unit will be operated.

Condition numbers for the ozone detection test fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to ozone measurements from 0.1 parts per million of ozone to no detectable trace of ozone. Values in this range should use the linear interpolation method to calculate the condition number.

Moderate: This category provides a condition number between 40 and 69. This corresponds to ozone measurements from 0.6 to 0. 1 parts per million. Values in this range should use the linear interpolation method to calculate-the condition number.

Major: This category provides a condition number between 10 and 39. This corresponds to ozone measurements from 0.8 to 0.6 parts per million. Values in this range use the linear interpolation method to calculate the condition numbers. Values above 0.8 parts per million are considered excessive, air usually require some form of ventilation to the outside of the powerhouse for safety reasons.

Filling Out Data Evaluation Sheet

2-24. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-25. Unit inspection should be performed on a quarterly basis. If substantial changes are observed, then readings may be taken on a monthly basis.

Partial Discharge Analysis (PDA) Test

Introduction

2-26. This evaluation is used to determine the condition of the generator based upon the analysis of partial discharges. Partial discharges are sparks which involve the flow of electrons and ions when a small volume of gas breaks down. The discharge is "partial" since there is a solid insulation, such as epoxy mica, in series with this partial discharge, preventing the complete breakdown. In generator stator windings, the partial discharges can occur as a slot discharge between the main insulation and the steel core, within voids or delamination in the groundwall insulation, in the endturn areas due to cracking, and at a deteriorating joint between the grading and semi-conductive areas of the coil.

Instructions for Evaluation

2-27. As previously discussed, the partial discharge analysis requires the installation of capacitive couplers in the machine and specific analytical methods to determine the particular values for partial discharges. Capacitive couplers are paired in a directional or differential cortiguration for system noise rejection. If this equipment is not installed and available, then this evaluation is omitted. The following general information is considered for the partial discharge analysis tests:

- There are three objectives of this tests: (1) determine the type and location of discharge; (2) monitor the level of this discharge; and (3) determine the degree of looseness in the winding. The partial discharge analyzer developed by Ontario Hydro Power Authority utilizes a pulse height analyzer module that counts the number of both positive and negative partial discharge voltage pulses at 16 distinct magnitude windows. Measurements are typically made at full load, speed no load, and at different stator winding temperatures to determine how the partial discharge is influenced by load and temperature. The logarithm of the pulse frequency (counts/sec) for each window is plotted against its pulse window magnitude. The type and relative location of the discharge can be determined from the Log (pulse frequency) vs Pulse Magnitude plots. A discharge identification summary is given in Table D-1.
- Generally, temperature sensitive discharge is indicative of internal voids or end-turn corona activity. Discharge that varies with load typically depicts a loose winding-, however, this load dependency should be observed in more than one PDA split or phase before concluding that the winding is loose. Normalized Quantity Numbers (NQN's) were developed to quantify discharge levels so long term trends could be established. NQN's are calculated by integrating the area under the Log (pulse frequency) vs Pulse Magnitude curves and normalizing this area to unity gain (gain setting = 1). NQN's are normally trended over time; however, they can also be used to determine the corona inception voltage level. This non-routine test can be performed by collecting data at several voltage levels while the unit is running speed no load. The NQN's are plotted against the generator terminal voltage and the inception voltage is found at the NQN=O

intercept. Table D-1 also gives typical ranges of the inception voltage for each discharge mechanism.

- The evaluator must determine the discharge mechanism from the criterion described above and whether the winding is loose or tight. If there is more than one discharge mechanism present, choose the mechanism that is the major contributor of the partial discharge activity. An NQN Modifier is determined from Table D-1 and multiplied by the highest NQN value observed at the normal operating condition, i.e., full load hot. The modified NQN values are used to determine the condition indicator value. The values provided below are general values. Some information has been shown which suggest that readings taken prior to the one-year "burn-in" period of the machine may not be accurate.
- Readings should be taken after the one-year period or after the partial discharge readings have stabilized. Should readings be different than those represented below, or if readings have not stabilized after a reasonable amount of time, the manufacturer should be contacted for additional information. If poor readings are obtained, additional tests and inspections may be warranted.
- There is insufficient historical data on machines to warrant the shutdown of the machine for poor readings. Because of this, the minimum condition number is 10.

Condition numbers for the partial discharge analysis test fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to partial discharge readings of 200 to 0 modified NQN. Values in this range should use the linear interpolation method to determine the condition number.

Moderate: This category provides a condition number between 40 and 69. This corresponds to partial discharge readings of 375 to 200 modified NQN. Values in this range use the linear interpolation method to determine the condition number.

Major: This category provides a condition number between 10 and 39.

Table D-1
Partial Discharge Analysis Identification Summary
Discharge Mechanism

	Slot Discharges	**End-Turn Corona Discharges**	**Delamination / Turn – Turn Insulation Discharges**	**Internal Discharges in Groundwall Voids**
Positive Pulse Predominance	Yes	Yes	No	No
Negative Pulse Predominance	No	No	Yes	No
Temperature Sensitive	No	Maybe – PD proportional to Temp.	Maybe – PD Proportional to 1 / Temp.	Yes – PD Proportional to 1 / Temp.
Load Sensitive	Mayve – PD Proportional to Load	No	Maybe – PD Proportional to 1 / Temp.	No
Corona Inception Voltage (Line-Line)	2 – 3 kV	> 6 kV	4 – 8 kV	4 – 8 kV
NQN Modifiers Loose Winding	1.00	0.85	0.50	0.45
NQN Modifiers Tight Winding	0.90	0.55	0.40	0.40

This corresponds to partial discharge readings of 500 to 375 modified NQN. Readings above 500 modified NQN have a condition number of 10.

Filling Out Data Evaluation Sheet

2-28. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-29. Partial discharge analysis readings should be performed on a semi-annual basis. If substantial changes are observed, then readings may be taken on a monthly basis.

Circuit Ring Inspection

Introduction

2-30. This evaluation is used to determine the condition of the generator based upon visual inspection of the circuit rings. These inspections may be performed after removing the upper and lower air shrouds. Examination of these areas should include close inspection for corona dusting, broken or loose blocking or lashings, discoloration, girth cracking and sponginess. The circuit rings should be examined closely around the support areas for shifting due to thermal expansion, and possible damage to the insulation system. Areas of concern should be referenced to the closest slot number.

Instructions for Evaluation

2-31. This procedure involves the careful inspection of the circuit rings. Condition numbers are based on the percentage of surface area where damage or problem areas are observed. The following general information is considered for the circuit ring inspection:

- Mirrors and hand held lights to inspect these areas are recommended.
- Areas of discoloration, sponginess of the insulation, tears in the insulation, and deposits of corona dust should be documented. The specific places where these flawed or suspect areas are found should be compared to previously documented damage.
- Complete documentation of the inspection should be provided, including the criteria for the particular rating.
- If inspection of the circuit rings shows that the unit has substantial damage or wear, then the condition number could be as low a 0.

Condition numbers for the circuit ring inspection fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to circuit ring problem areas (sponginess, discoloration, corona dusting and girth cracking) from 15 to 0% of the total surface area. Percentages between these two values should use the linear interpolation method.

Moderate: This category provides a condition number from 40 to 69. This corresponds to circuit ring problem areas (sponginess, discoloration, corona dusting, girth cracking and signs of wear due to movement, but with no insulation damage) from 30 to 15% of the total surface area. Percentages between these two values should use the linear interpolation method.

Major: This category provides a condition number between 0 and 39. This corresponds to circuit ring problem areas (sponginess, discoloration, corona dusting, girth cracking and damage to the insulation due to movement) from 50 to 30% of the total surface area. Percentages between these two values should use the linear interpolation method. A failing joint or severely damaged insulation will have a value of 0.

Filling Out Data Evaluation Sheet

2-32. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-33. Unit inspection should be performed during unit overhaul or every 5 years, whichever comes first.

Core Inspection

Introduction

2-34. This evaluation is used to determine the condition of the generator based upon the core inspection. Core inspection may be done with the rotor in place. However, it is more convenient to examine the core with the rotor removed. The core should be examined for looseness and shifting. Examine to see if there are any laminations which protrude into the air gap, or signs of fretting corrosion. Stator core looseness should be checked with the knife test. Stator through bolt torques should also be checked. Specific locations are referenced to the closest slot number. Improperly re-torquing the through bolts may cause the core to shift or buckle. This should be avoided.

Instructions for Evaluation

2-35. The core inspection may be accomplished with the rotor in or out, but inspection will be greatly facilitated if the rotor is removed. The core should be inspected for fretting corrosion, corona dusting, movement of laminations, looseness of laminations, chevroning at the splits, split bolt torques and through bolt torques. Looseness should be examined by the knife test, i.e. making sure that a knife (maximum blade thickness 0.01") cannot be inserted more than 1/8' laminations. Condition numbers are based on the percentage of surface area with lamination problems. The following general information is considered for the core inspection:

- Specific information regarding areas which have unusual findings should be documented.
- If particular areas are felt questionable, additional inspection should be done. This may be accomplished through removing one or more water coolers, and inspecting the back side of the iron. If a bore scope is available, then this may also be used.
- A standardized core inspection procedure should be developed and followed.

Condition numbers for the core inspection fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to areas of lamination problems (fretting, waviness, corona activity, looseness between laminations) of 15 to 0% of the total lamination surface area with no buckled or broken laminations or chevroning at the splits. Percentages between these two values should use the linear interpolation method.

Moderate: This category provides a condition number between 40 and 69. This corresponds to areas of lamination problems (fretting, waviness, corolla activity, looseness between laminations) of 30 to 15% of the total lamination surface area with chevroning at the splits, but no buckled or broken laminations. Percentages between these two values should use the linear interpolation method.

Major: This category provides a condition number between 0 and 39. This corresponds to areas of lamination problems (fretting, waviness, corona activity, looseness between laminations) of 50 to 30% of the total lamination surface area with moving laminations. Percentages between these two values should use the linear interpolation method. Percentages of above 50% have a value of 0. Also, any broken clamping plates, broken through bolts, major iron movement, missing packets of iron, broken teeth will have a value of 0. These items should be repaired with a consolidating epoxy or other means before being categorized above 0.

Filling Out Data Evaluation Sheet

2-36. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-37. Core inspection should be performed during unit overhaul or every 5 years, whichever comes first.

Endturn Inspection

Introduction

2-38. This evaluation is used to determine the condition of the generator based upon visual inspection of the endturns. This inspection may be performed after removing the upper and lower air shrouds. Examination of the endturn areas should include close inspection for corona dusting, broken blocking or lashings, discoloration, girth cracking and sponginess. Areas of concern should be referenced to the closest slot number.

Instructions for Evaluation

2-39. This procedure involves the careful inspection of the endturns. Condition numbers are based on the percentage of endturns where damage or problem areas are observed. The following general information is considered for the endturn inspection:

- Mirrors and hand held lights to inspect these areas are recommended.
- Areas of discoloration, sponginess of the insulation, tears in the insulation, and deposits of corona dust should be documented. The specific places where these flawed or suspect areas are found should be compared to previously documented damage.
- Complete documentation of the inspection should be provided, including the criteria for the particular rating.
- If inspection of the endturns shows that the unit has substantial damage or wear, then the condition number could be as low a 0.

Condition numbers for the endturn inspection fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to endturn problem areas (sponginess, discoloration, corona dusting and girth cracking) from 15 to 0% of the total number of endturns. Percentages between these two values should use the linear interpolation method.

Moderate: This category provides a condition number from 40 to 69. This corresponds to endtum problem areas (sponginess, discoloration, corona dusting, girth cracking and torn insulation) from 30 to 15% of the total number of endturns. Percentages between these two values should use the linear interpolation method.

Major: This category provides a condition number between 0 and 39. This corresponds to endturn problem areas (sponginess, discoloration, cororta dusting, girth cracking and torn insulation) from 50 to 30% of the total number of endturns. Percentages between these two values should use the linear interpolation method. A deterioration of form in any endturn whereby the individual strands can move will have a value of 0.

Filling Out Data Evaluation Sheet

2-40. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-41. Endturn inspection should be performed during unit overhaul or every 5 years, whichever comes first.

Lead Inspection

Introduction

2-42. This evaluation is used to determine the condition of the generator based upon visual inspection of the leads. This inspection may be performed after removing some covers. Examination of the leads should include close inspection for corona dusting, broken blocking or lashings, discoloration, girth cracking and sponginess. Areas of concern should be referenced such that they can be reexamined later.

Instructions for Evaluation

2-43. This procedure involves the careful inspection of the leads. Condition numbers are based on the percentage of lead area where damage or problem areas are observed. The following general information is considered for the lead inspection:

- Mirrors and hand held lights to inspect these areas are recommended.
- Areas of discoloration, sponginess of the insulation, tears in the insulation, and deposits of corona dust should be documented. The specific places where these flawed or suspect areas are found should be compared to previously documented damage.
- Complete documentation of the inspection should be provided, including the criteria for the particular rating.
- If inspection of the leads shows that the unit has substantial damage or wear, then the condition number could be as low a 0.

Condition numbers -for the lead inspection fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to lead problem areas (sponginess, discoloration, corona dusting and girth cracking) from 15 to 0% of the total area of the leads. Percentages between these two values should use the linear interpolation method.

Moderate: This category provides a condition number from 40 to 69. This corresponds to lead problem areas (sponginess, discoloration, corona dusting, girth cracking and torn insulation) from 30 to 15% of the total area of the leads. Percentages between these two values should use the linear interpolation method.

Major: This category provides a condition number between 0 and 39. This corresponds to lead problem areas (sponginess, discoloration, corona dusting, girth cracking and torn insulation) from 50 to 30% of the total area of the leads. Percentages between these two values should use the linear interpolation method. A deterioration in any lead whereby the lead is becoming detached will have a value of 0.

Filling Out Data Evaluation Sheet

2-44. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-45. Lead inspection should be performed during unit overhaul or every 5 years, whichever comes first.

Slot Inspection

Introduction

2-46. This evaluation is used to determine the condition of the generator based upon visual inspection of the contents of several unwedged slots. If the rotor is left in place, one or two pole pieces must be removed in order to inspect the slot contents. The unit must be rotated by hand in order to inspect different slots. Internal slot contents may be examined by unwedging the slot and examining the top portion of the front coil, top fillers and side filters. This may be done randomly on one to two percent of the slots.

Instructions for Evaluation

2-47. This procedure involves the careful visual inspection of the contents o f some slots after being unwedged. Condition numbers are based on the percentages of loose side fillers and remaining slot paint. Inspection with the rotor in will require that one or two (or more as needed) rotor pole pieces be removed, and the unit rotated by hand. Internal slot contents should be inspected on slots which have the wedges removed. Side filler, top filler and coil surface conditions should be inspected. The following general information is considered for the slot inspection:

- The coil lateral looseness should be checked using a 0.002" feeler gauge between the coil and the iron on the side filler side of the coil over the entire length of the slot. The length of the slot, the consecutive inches of feeler gauge passage and total inches of feeler gauge passage should be recorded.
- All wedges and fillers should be checked for signs of overheating. Spare wedges and fillers available if the removed wedges and filters are damaged.
- Complete documentation of the inspection should be provided, including the criteria for the particular rating.

Condition numbers for the slot inspection fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to 10 to 0% loose side filler (total inches of feeler gauge passage divided by slot length). Percentages between these two values should use the linear interpolation method. 'Mere should be no slots that have more than six consecutive inches of feeler gauge passage. There should be more than 90% of the coil slot paint remaining and no damage apparent to the coil insulation. Top filler shall be intact with some minor signs of heat or corona damage.

Moderate: This category provides a condition number between 40 and 69. This corresponds to 30 to 15% loose side filler. Percentages between these two values should use the linear interpolation method. There should be no slots that have more than one occurrence when feeler gauge passage exceeds six inches. There should be more than 50% of the coil slot paint remaining and only minor damage apparent in the coil insulation (pitting affecting less than five layers of groundwall insulation). Top filler shall be intact with signs of heat or corona damage.

Major: This category provides a condition number between 10 and 39. This corresponds to 30 to 15% loose side filler. Percentages between these two values should use the linear interpolation method. There should be no slots that have more than two occurrence when feeler gauge passage exceeds six inches. There should be more than 25% of the coil slot paint remaining and only min6r damage apparent in the coil insulation (pitting affecting less than five layers of groundwall insulation). Top filler shall be intact with signs of heat or corona damage. In cases where inspection reveals imminent failure, this category provides a condition number of 0.

Filling Out Data Evaluation Sheet

2 -48. Column 1 lists the condition indicator- name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-49. Slot inspection should be performed during unit overhaul or every five years, whichever comes first.

Wedge System Inspection

Introduction

2-50. This evaluation is used to determine the condition of the generator based upon visual inspection of the wedge system. If the rotor is left in place, one or two pole pieces must be removed in order to inspect the wedge system. The unit must be rotated by hand in order to inspect the wedges. The wedging system should be examined closely for loose, broken or burnt wedges.

Instructions for Evaluation

2-51. This procedure involves the careful visual inspection of the wedge system. Condition numbers are based on the percentage of loose wedges. Inspection with the rotor in will require that one or two (or more as needed) rotor pole pieces be removed, and the unit rotated by hand. The following general information is considered for the wedge system inspection:

Wedge systems may be examined by tapping the wedges with a blunt metallic instrument (such as the ground end of a file) which rings or vibrates when hit against a solidly wedged slot. Commercial wedge tightness tools are also available.

- Depending on the time available for the inspection, it is desirable to examine the entire machine for wedge and slot tightness.
- Some wedging systems use spring filler material, designed to keep constant pressure on the coils after the materials have undergone their thermal setting. Many of these systems have the capability of checking the spring deflection by having small inspection holes in the wedge.
- Complete documentation of the inspection should be provided, including the criteria for the particular rating.

Condition numbers for the wedge system inspection fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This corresponds to 10 to 0% loose wedges. Percentages between these two values should use the linear interpolation method. There should be no slots that are completely loose.

Moderate: This category provides a condition number between 40 and 69. This corresponds to loose wedges in 30 to 15% of the total number of slots in the unit. Percentages between these two values should use the linear interpolation method. There should be no slots that are completely loose.

Major: This category provides a condition number from 10 to 39. This corresponds to loose wedges in 30 to 50clo of the total number of slots in the unit. Percentages between- these two values should use the linear interpolation method. If an entire slot is loose, this category provides a condition number of 10. In cases where inspection reveals imminent failure, this category provides a condition number of 0.

Filling Out Data Evaluation Sheet

2-52. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-53. Wedge system inspection should be performed during unit overhaul or every five years, whichever comes first.

Reduced Ratings Due to Known Failures

Introduction

2-54. This evaluation is used to determine the condition of the generator based upon components that have failed and have not been replaced. This information, although requiring some historical background information of the unit, examines only the present condition of the unit, as a result of its previous operating failures. These failures may have resulted in the removing of coils in the machine, which in turn may have reduced the rating of the machine. Other failures or damage should also be considered, such as core shifting or rotor damage as a result of known system faults. Information such as temperature records, loading information, and system information should be maintained.

Instructions for Evaluation

2-55. The aspect of reduced ratings due to known failures is one where the unit has undergone a change in operating mode. The unit has possibly undergone a three phase sudden short circuit. Perhaps one or more coils have shorted to ground. In order to put this unit back on line as soon as possible, it may have been necessary to jumper around the damaged coil or coils. Perhaps there were not enough coils to do half coil splices and jumpering was necessary. Perhaps due to the system fault, the core was damaged. There are many different scenarios which can result in changes to the unit, and having to reduce the rating of the unit. Conditions which can affect the

rating of the unit, after coil removal, are the number of coils removed, and the position of the removed coil in the winding. Large imbalances in the winding may cause increased circulating currents, increased heat, and decreased ratings. Complete documentation of the failure and calculation of the reduced rating should be provided.

Condition numbers for reduced ratings due to known failures fall into the following three categories:

Minor: This category provides a condition number between 70 and 100. This range corresponds to a condition where coils may have been removed, but there was no change in rating. As an example, if no coils were removed, there would be no rating change. If up to 1% of the coils were removed, and there was no perceivable rating change, then the condition number would be 75. Values in this range should use the linear interpolation method.

Moderate: This category provides a condition number between 40 and 69. This range corresponds to a condition where coils may or may not have been removed, and a change in rating has occurred. This may be a change on the order of 5% of the maximum nameplate rating. To determine the intermediate values, the linear interpolation method should be used.

Major: This category provides a condition number between 10 and 39. This range corresponds to a condition where coils may or may not have been removed and a change of rating has occurred. This may be from over a 5% change of rating to a 15% change of rating (from maximum nameplate). To determine intermediate values, the linear interpolation method should be used. Derating the unit more than 15% would have an automatic condition number of 10.

There may be circumstances where, for the particular plant, a reduced rating for the unit may not be acceptable. This should be documented with the reasons for not being able to run the unit at the reduced rating, including any official documents and Memorandums of Understanding between the generation and transmission agencies.

Filling Out Data Evaluation Sheet

2-56. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

2-57. This inspection is based on continuous operating information. Therefore this condition number remains constant until a failure occurs.

Linear Intelpolation Method

2-58. The following general equation is provided to determine values through the linear interpolation method:

$$CN2 = \frac{CN3 - [(CN3 - CN1) \times (MV1 - MV2)]}{MV3 - MV1}$$

Where:

MV1 = Lower limit of the measured value range (i.e. Minor, Moderate, High)

AW2 = Actual measured value

MV3 = Upper limit of the measured value range (i.e. Minor, Moderate, High)

CN1 = Lower limit of the condition number range (i.e. Minor, Moderate, High)

CN2 = Desired condition number to be determined

CN3 = Upper limit of the condition number range (i.e. Minor, Moderate, High)

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Generator Condition

Unit No._____

Project: _____

Manufacturer: _____

Prepared by: _____ Date:_____

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Blackout Test			
Corona Probe Test			
DC High Potential Test			
Insulation Resistance			
Ozone Detection Test			
Partial Discharge Analysis Test			
Circuit Ring Inspection			
Core Inspection			
Endturn Inspection			
Lead Inspection			
Slot Inspection			
Wedge System Inspection			
Reduced Rating			
Overall Generator Condition Index Rating			

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Blackout Test

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Description of Problems Noticed

Temperature: Humidity: Test Voltage Used:
Test Equipment Used:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Corona Probe Test

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Readings			Description of Problems Noticed
	Top	Middle	Bottom	

Maximum Reading: Median Reading:
Corona Inceptian Voltage: Corona Extinction Voltage:
Temperature: Humidity: Test Voltage Used:
Test Equipment Used:
Other:

REMR Hydropower Condition
Indicator Program

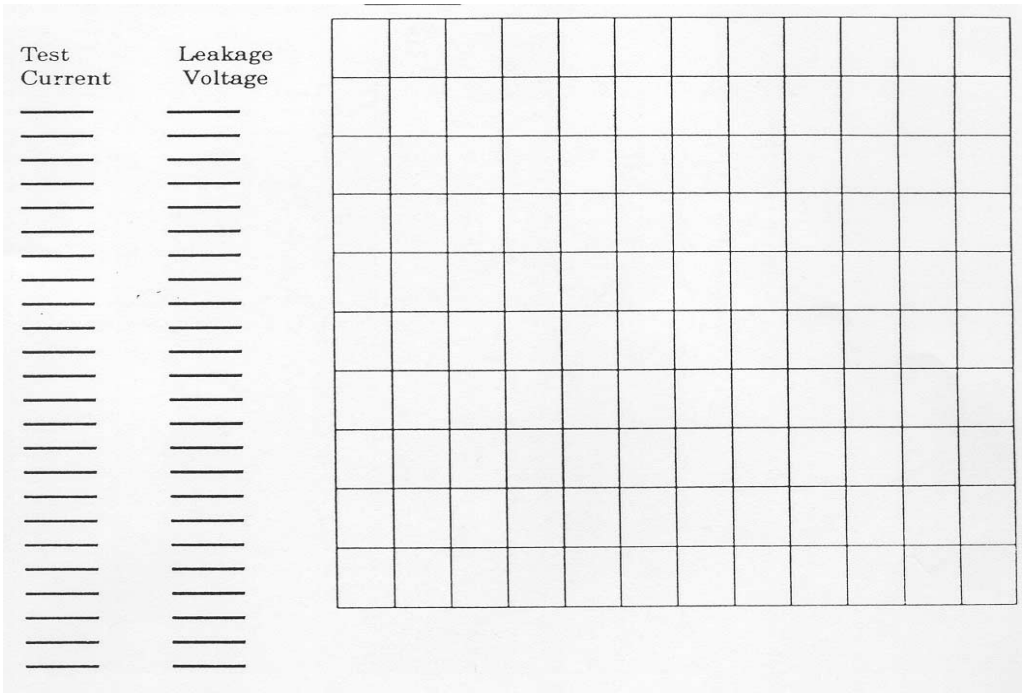
Data Collection Sheet
DC High Potential Test

Project: _____ *Unit No.*_____

Manufacturer: _____

Prepared by: _____ Date:_____

Phase: _____
Microamps @ 1 Min. _____ Microamps @10 Min. _____
Polarization Index: _____



Temperature: Humidity:
Test Equipment Used:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Insulation Resistance Test

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Phase(s): _____

Insulation Resistance in Megohms at 1 Minute: _____

Insulation Resistance in Megohms at 10 Minutes: _____

Polarization Index: _____

Insulation Resistance in Megohms at _____ Minutes: _____
Corrected to 40 degrees C:
_____

Temperature: Humidity: Test Voltage Used:
Test Equipment Used:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Ozone Detection Test

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Concentration in parts per million: _____

Location of reading: _____

Generator Terminal Voltage: _____

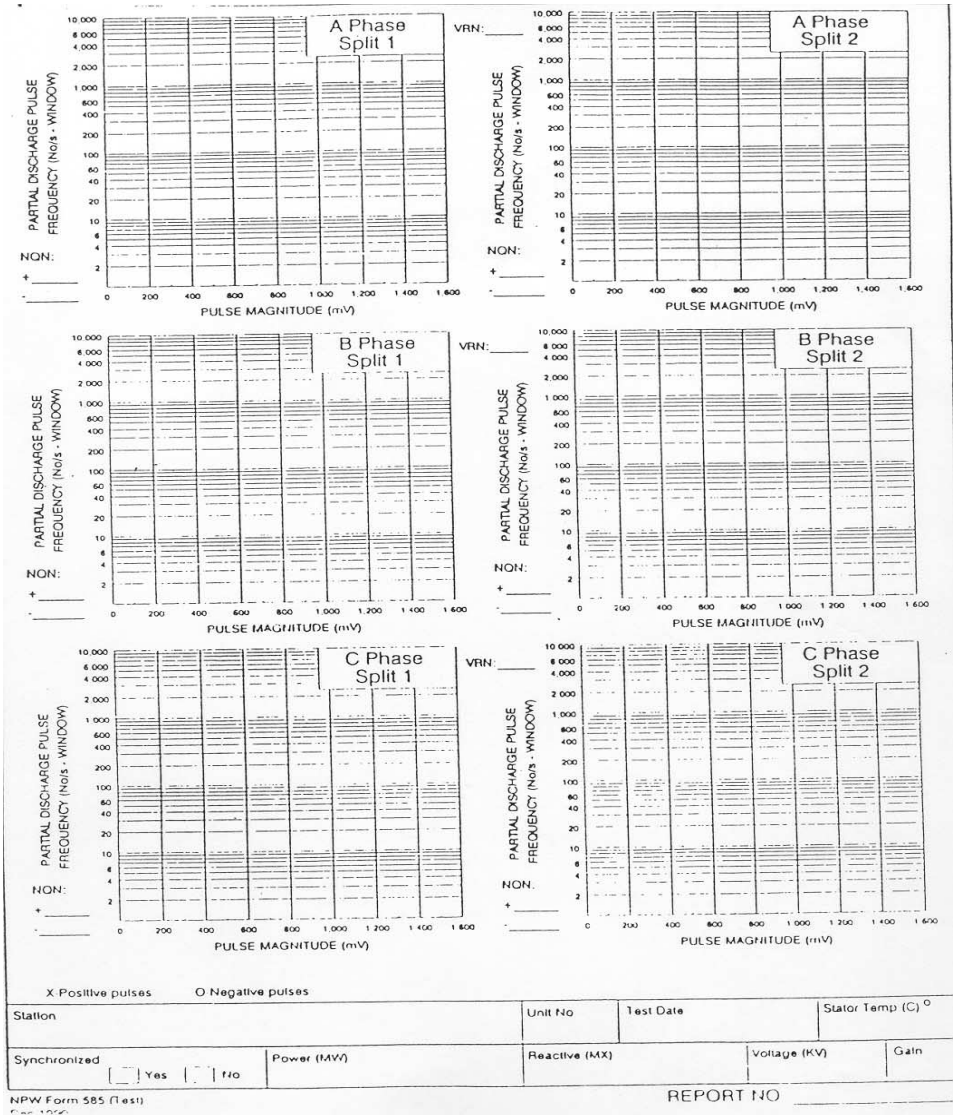
Generator Loading, MW: _____

Generator Loading, MVAR: _____

Temperature: Humidity: Test Voltage Used:
Test Equipment Used:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Partial Discharge Anlaysis Test



REMR Hydropower Condition Indicator Program

Data Collection Sheet
Circuit Ring Inspection

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Description of Problems Noticed (referenced to nearest slot)

Temperature: Test Voltage Used:
Equipment Used:
Number of Rings: Number of Slots:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Core Inspection

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Description of Problems Noticed

Equipment Used:
Height: Inside Diameter: Number of Slots:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
End Turn Inspection

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Description of Problems Noticed (referenced to nearest slot)

Equipment Used: _____
Number of Slots: _____
Other: _____

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Lead Inspection

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Description of Problems Noticed

Equipment Used:
Number of Rings:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Slot Inspection

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Description of Problems Noticed

Equipment Used:
Types of Fillers:
Filler Material:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Wedge System Inspection

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Slot Number	Description of Problems Noticed

Equipment Used:
Wedge Type:
Wedge Material:
Other:

REMR Hydropower Condition Indicator Program

Data Collection Sheet
Reduced Ratings Due to Known Failures

Project: _____ Unit No._____
Manufacturer: _____
Prepared by: _____ Date:_____

Failure Information

Calculation of Reduced Rating

PART III: EXCITATION SYSTEMS

Note: Field review comments on this section were received in September 1992. These comments will be incorporated in the next revision to this section. They will require extensive changes and there was not enough time to incorporate them in this revision to the CI manual. This section will be revised using IEEE 421.2-1990. Condition indicators in the next revision will be based on large signal performance criteria, small signal performance criteria, excitation control system stability as well as some of the indicators presently contained in the program.

Condition Index Scale

Value	Condition Description	
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate.
25.-39	Poor	Serious deterioration in at least some portions of equipment. Function is inadequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure D-1

Program, Format and Method

Explanation of Program

3-1. The overall excitation system index rating is a number between 0 and 100 which will be used to define the present condition of the excitation system. The number will be used in the REMR Condition Index Scale which is shown below.

The overall condition index is calculated from a series of tests and inspections, which are discussed later in this section. The criteria behind these tests and inspections are such that they may be performed during an annual maintenance period (generally 1-2 weeks).

The following tests and inspections are a major cross section of what industry presently examines to determine Excitation system condition:

1. Commutator Inspection (Rotating Exciter)
2. Droop Characteristics Test
3. Insulation Resistance Test (Rotating Exciter)
4. Off-Line Step Response Test
5. On-Line Load/Voltage Response Test

Specific test procedures and descriptions will not be covered in this Condition Indices Program. It is assumed that individuals performing the tests to determine a condition have performed these tests previously, and have had experience in the testing and inspection of hydroelectric generators and exciters. Only experienced personnel should attempt to perform these tests.

Conditions such as obsolescence, lack of features, and lack of spare parts are not discussed in this section since these have nothing to do with the present condition of the exciter. Condition assessments may be made with comparison to previous test results for specific tests. This is called trending. An example of this is the off-line step response test results. Since trending is necessary to determine present exciter condition, accurate record keeping is an absolute requirement in a successful Condition Indices Program. In addition to the written records required for trending, records such as photos, and in some cases, a video of the area of concern, along with a narrative of the items which are of concern may be included.

When a unit is new and has met all guaranteed requirements of the original contract and has very few operating hours, it may be assumed that the unit is operating at its peak condition. At this point, it is- therefore assumed that if any one of the tests were conducted, that the result of the test would be a condition of 100. As a unit ages, or logs additional operating hours, then this condition will drop from the as-new condition of 100 to a lower value.

Individual tests and inspections may not have the same importance or weight as other tests. The overall condition index value will be determined from the lowest individual condition index. If no previous test data is available, or the test shown is not done, then the condition for that individual test should be 100.

Explanation of Format

3-2. he formats used to discuss the various tests and inspections for obtaining the condition numbers for an exciter are similar. The first section is an introduction which describes the test or

inspection. The second section gives instructions on how to perform the test or inspection. The third section explains how to perform the evaluation of the data and how to fill out the appropriate part of the Data Evaluation Sheet. The final section gives the recommended frequency of performing the test or inspection.

Explanation of Method

3-3. condition number between 0 and 100 is determined based on the results of tests and inspections. The overall condition index rating for the excitation system is the lowest value of any of the condition numbers.

Overall Exciter Condition

Introduction

3-4. he overall exciter condition is calculated using the following condition indicators:

1. Commutator Inspection (Rotating Exciter)
2. Droop Characteristics Test
3. Insulation Resistance Test (Rotating Exciter)
4. Off-Line Step Response Test
5. On-Line load/Voltage Response Test

Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various tests and inspections which are discussed later.

Filling Out Data Evaluation Sheet

3-5. column 1 lists the 5 condition indicators which are used for exciter evaluation. Others may be added in the future. Fill in the date the test or inspection was made in column 2. Insert any notes or remarks about the condition number in column 3. For instance, if the condition number is low, put in the reason for it being low. Put the condition number for the particular condition indicator in column 4.

The overall exciter condition index rating is the lowest of the individual condition indicator numbers. This rating is placed in the box in the lower right corner of the Overall Exciter Condition Data Evaluation Sheet.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Excitation System Condition

Project: *Old Hydro Plant* *Unit No. 1*

Prepared by: *I.N. Spector* Date: *7/3/90*

Item	Date of Inspection or Test	Remarks	Condition Number 0 - 100
Commutator Inspection (Rotating Exciter)	6/5/90	*Commutator damage = 25%* *Remaining commutator = 60%*	*60*
Droop Characteristics Test	*6/6/90*	*Some oscillation between units. Oscillations last for 30-40 seconds. Powerhouse reliability effected.*	*40*
Insulation Resistance Test (Rotating Exciter)	*6/4/90*	*Megohm reading = 2.5* *Exciter Rated: 250 volts*	*55*
Off-Line Step Response Test	*2/15/90*	*Exciter dampens the oscillation. System requirements for synchronizing time are not met. Some manual control is required when synchronizing.*	*40*
On-Line Load / Voltage Response Test	*2/15/90*	*Exciter dampens the oscillation. System requirements for response time are not met. Some manual adjustment is required.*	*40*
		Overall Excitation System Condition Index Rating	*40*

A sample of this form is shown on page 3-5. Information to be completed by the field is shown in script text.

Commutator Inspection (Rotating Exciter)

Introduction

3-6. This evaluation is used to determine the condition of the exciter based upon visual inspection of the commutator. The rotating exciter should be examined for arcing and discoloration of the slip rings, as well as areas where the insulation system is suspect. The areas should be referenced by particular position, slot number, and specific surface areas.

Instructions for Evaluation

3-7. This procedure involves the careful inspection of the commutator. Condition numbers are based on the percentage of surface area where damage or problem areas are observed. The condition numbers are also based on the ability of the commutator to be undercut and stoned. The following general information is considered for the commutator inspection:

- Damage to the commutator can be described by color, pitting, cracking, etc.
- Damage to the commutator can usually be remedied by stoning and undercutting as necessary. These actions remove a portion of the remaining life.
- Accurate measurements of the initial commutator diameter and the, existing diameter are required.
- Complete documentation for the inspection should be provided, including the criteria for the particular rating.

Condition numbers for the commutator inspection fall into the following three categories:

Minor: This category provides a condition number from 70 to 100. These values correspond to the percentage of useful commutator remaining in the range of 70 to 100%. There should be less than 15% damage to the commutator.

Moderate: This category provides a condition number from 40 to 69. These values correspond to the percentage of useful commutator remaining in the range of 40 to 69%. There should be less than 30% damage to the commutator.

Major: This category provides a condition number from 10 to 39. These values correspond to the percentage of useful commutator remaining in the range of 0 to 39%. There should be less than 50% damage to the commutator. If the damage exceeds 50%, the condition number is 10.

Filling Out Data Evaluation Sheet

3-8. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

3-9. Commutator inspection should be performed during major unit overhaul or every five years, whichever comes first.

Droop Characteristics (VAR Sharing)

Introduction

3-10. This evaluation is used to determine the condition of the exciter based upon exciter droop characteristics.

Instructions for Evaluation

3-11. This procedure involves the testing of the exciter for droop characteristics. Condition numbers are based on the ability of the exciter to operate within system and powerhouse requirements for reliability. The following general information is considered for the droop characteristics:

- Droop is used to describe the behavior of the exciter when there are two or more units connected to the same transformer thus sharing-vars.
- There are no defined testing procedures to reference for this testing. The test should follow that which was performed originally when the equipment was installed.
- While var sharing is necessary on units sharing one transformer bank, it is not one which is critical to the operation of the exciter, nor will it make the exciter inoperable if the feature is not functioning.
- Complete documentation for the testing should be provided, including the criteria for the particular rating.

Condition numbers for the droop characteristics fall into the following three categories:

Minor: This category provides a condition number from 70 to 100. These values correspond to the units sharing vars without oscillating between the units. Proportionally sharing the vars with respect to unit loading is rated 100. Unproportionally sharing the vars, without oscillating and meeting acceptable powerhouse operation standards, is rated 70.

Moderate: This category provides a condition number from 40 to 69. These values correspond to the units sharing vars with some oscillation between the units. The duration of the oscillation determines the rating. Oscillations must damp out to be rated as moderate. The oscillations shall not effect the reliability of the system. Powerhouse reliability is moderately effected depending on the frequency and amplitude of the swinging vars.

Major: This category provides a condition number from 10 to 39. These values correspond to the units sharing vars with undamped oscillations between the units involved. The amplitude of the oscillations determines the rating. Powerhouse and system reliability are both effected by the oscillations. If the var sharing capability of the units has to be disabled, the rating is 10.

Filling Out Data Evaluation Sheet

3-12. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

3-13. The VAR sharing device should be tested during major unit overhaul or every five years, whichever comes first.

Insulation Resistance Test (Main Exciter)

Introduction

3-14. This evaluation is used to determine the condition of the exciter based upon the insulation resistance. In a rotating exciter, the insulation resistance test is an excellent method in determining the condition of the main exciter windings. These tests are also discussed in the generator condition indices program.

Instructions for Evaluation

3-15. The insulation resistance test may need to be performed twice depending on the test results obtained. A preliminary test should be performed at the time when the unit is taken down for maintenance. If a unit has a great deal of surface moisture, surface contamination or insufficient drying time was allotted following cleaning with solvents, then a poor insulation resistance reading may result. If this is the case, the winding should be inspected, cleaned and retested. The following general information is considered for the insulation resistance test:

- Test values for insulation resistance test should be documented. The same value should be used if possible for all tests. This will allow for some comparison between previously performed tests.
- Insulation resistance measurements are made at 1 minute and 10 minute intervals to check the polarization index.
- With the decrease of current with time, the insulation resistance measured at the 10 minute time interval will be higher than the 1 minute time interval. If the insulation is clean and dry, the insulation resistance will increase for 10 minutes or longer. If the insulation is dirty, a constant value of the insulation resistance will be reached in 1 to 2 minutes. For an exciter of 500 volts operating voltage, the minimum value of insulation resistance allowable before returning the unit back to service is 0.50 megohms, at 400°C for the entire winding using 1 megohm per 1000 volts as the general rule.

Condition numbers for the insulation resistance test (main exciter) fall into the following three categories: (Note that these values are for the insulation resistance at the 10 minute time period of a 500 volt rated exciter, resistances below will change proportionally as the rating of the exciter changes)

Minor: This category provides a condition number from 70 to 100. These values correspond to an insulation range of 5 to 50 megohms. Insulation resistance readings between these two values shall use the linear interpolation method to determine the condition number.

Moderate: This category provides a range of condition numbers from 40 to 69. These ranges correspond to insulation resistance ranges of I to 5 megohms. Insulation resistance readings between these two values shall use the linear interpolation method to determine the value.

Major: This category provides a condition number range from 10 to 39. These deduct ranges correspond to insulation resistance ranges of 0.5 to 1 megohms. Insulation resistance readings between these two values shall use the linear interpolation method to determine the value.

Filling Out Data Evaluation Sheet

3-16. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

3-17. Insulation resistance tests should be performed during a major unit overhaul, or every five years, whichever comes first.

Off-Line Step Response Test

Introduction

3-18. This evaluation is used to determine the condition of the exciter based upon the off-line step response test. This test is covered in detail in IEEE 421A, "IEEE Guide for Identification, Testing, and Evaluation of Dynamic Performance of Excitation Control Systems". In brief, an error signal is introduced into the excitation control system, while the unit is off-line, and response is examined, through oscillograph readings. As with the on-line test, a bench mark must be made of the off-line characteristics for reference if no original test data is available.

Instructions for Evaluation

3-19. The off-line step response test is a measurement of unit response to operator or automatic control adjustments when synchronizing the unit. The following general information is considered for the off-line step response test:

- Any change in plant operation (base loading to peaking, new auto synchronizer) will likely change the condition number.
- The condition number is dependent on the needs of the power system as concerns system reliability.
- Complete documentation for the test should be provided, including the criteria for the particular rating.

Condition numbers for the off-line step response fall into the following three categories:

Minor: This category provides a condition number from 70 to 100. These values correspond to the exciter being able to perform the step respons6 and dampen the oscillation in generator terminal voltage allowing synchronization within system requirements for reliability. An exciter being able to dampen the oscillation and exceed system requirements for synchronizing time is rated 00. An exciter being able to dampen the oscillation and meet system requirements for synchronizing time is rated 70.

Moderate: This category provides a condition number from 40 to 69. These values correspond to the exciter being able to perform the step response and dampen the oscillation in generator terminal voltage allowing synchronization after some delay and additional adjustment. An exciter being able to dampen the oscillation, but failing to meet system requirements for synchronizing time, is rated 69. An exciter being able to dampen the oscillation, but failing to meet system requirements for synchronizing time and requiring some manual adjustment, is rated 0.

Major: This category provides a condition number from 10 to 39. These values correspond to the exciter failing the step response test (oscillations remain for extended time). An exciter which fails the step response test but can be operated by an autosynchronizer is rated 39. An exciter which fails the step response test and can only be operated manually is rated 10.

Filling Out Data Evaluation Sheet

3-20. Column I lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

3-21. Off line tests should be performed just prior to major unit overhaul, or every five years, whichever comes first.

On-Line Load/Voltage Response Test

Introduction

3-22. This evaluation is used to determine the condition of the exciter based upon the on-line load/voltage response test. The exciter, as delivered to site, was required to meet certain response requirements relating to load and voltage changes. If original test data is not available, complete field testing of the excitation control system would be necessary. Testing should be done through IEEE 421A, "IEEE Guide for Identification, Testing, and Evaluation of Dynamic Performance of Excitation Control Systems".

Once bench mark data is available, future tests may be compared to this data. Because data varies between exciters, there is no general data which can be compared. The gauge to be compared in this case win be a forced step response. Items such as excitation system overshoot in the controlling of voltage during the test must be examined. An oscillograph reading of the response during the test is required.

Instructions for Evaluation

3-23. The on-line load/voltage response test is a measurement of unit response to operator or automatic control adjustments when the unit is online. The following general information is considered for the on-line load/ voltage response test:

- Any change in plant operation (base loading to peaking) will likely change the condition number.
- The condition number is dependent on the needs of the power system as concerns system reliability.

- Complete documentation for the test should be provided, including the criteria for the particular rating.

Condition numbers for the on-line load/voltage response test fall into the following three categories:

Minor: This category provides a condition number from 70 to 100. These values correspond to the exciter being able to perform the step response and dampen the oscillation within system requirements for reliability. An exciter being able to dampen the response and exceed system requirements for response time is rated 100. An exciter being able to dampen the oscillation and meet system requirements for response time is rated 70.

Moderate: This category provides a condition number from 40 to 69. These values correspond to the exciter being able to perform the step response and dampen the oscillation after some delay and additional adjustment. An exciter being able to dampen the oscillation, but failing to meet system requirements for response time, is rated 69. An exciter being able to dampen the oscillation, but failing to meet system requirements for response time and requiring some manual adjustment, is rated 40.

Major: This category provides a condition number from 10 to 39. These values correspond to the exciter failing the step response test (oscillations remain for extended time). An exciter which fails the step response test but can still be operated in the automatic mode is rated 39. An exciter which fails the step response test and can only be operated in manual mode is rated 10.

Filling Out Data Evaluation Sheet

3-24. Column 1 lists the condition indicator name. Fill in the date on which the inspection was made in column 2. Make any comments or notes on the condition of parts inspected in column 3. Finally, in column 4, enter the condition number based on the criteria listed above.

Frequency of Inspection

3-25. On-line response to load/voltage changes tests should be performed before a unit overhaul, or every five years, whichever comes first.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Excitation System Condition

Project: _____ *Unit No.*_____

Prepared by: _____ Date:_____

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Commutator Inspection (Rotating Exciter)			
Droop Characteristics Test			
Insulation Resistance Test (Rotating Exciter)			
Off-line Step Response Test			
On-Line Load/ Voltage Response Test			
		Overall Generator Condition Index Rating	

PART IV: CIRCUIT BREAKERS

Program, Format and Method

Explanation of Program

4-1. Circuit breakers are obtained from a variety of manufacturers, and there is a large variety of different designs. Specifications apply only to the particular circuit breaker being considered, and are not necessarily applicable to those produced by other manufacturers. Even within a single manufacturer, different models of circuit breakers may not have the same design or specifications. Therefore, it is necessary to refer to the manufacturer's data for each circuit breaker that is studied.

The overall circuit breaker condition is expressed by a number between 0 and 100 which defines the present condition of the breaker. For circuit breakers, the Condition

Condition Index Scale

Value	Condition Description	
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate.
25.-39	Poor	Serious deterioration in at least some portions of equipment. Function is inadequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure D-1

Index Scale listed below is broken into three broad levels as specified below:

85-100:	Excellent: All parts functional, operation within specifications.
40-84:	Good: All parts functional, minor adjustments required, evidence of minor wear.
0-39:	Failure: Failure of a component, replacement required. Breaker is incapable of interrupting a fault.

Explanation of Format

4-2. The condition indices for circuit breakers all have a similar format. The first section is an introduction which describes the test or inspection. The second section gives instructions on how to perform the test or inspection. The third section explains how to perform the evaluation of the data and how to fill out the appropriate part of the Data Evaluation Sheet. The final section gives the recommended frequency of performing the test or inspection.

Explanation of Method

4-3. A condition number between 0 and 100 is determined for each condition indicator based on various tests and inspections performed on the circuit breaker. The overall condition number for the breaker is the lowest value of any of the condition numbers obtained. Representative tests and inspections are described below. Sample evaluation forms for both air and oil circuit breakers follow. Information to be completed by the field is shown in script text.

Overall Circuit Breaker Condition

Introduction

4-4. The overall circuit breaker condition is calculated using several condition indicators, including: condition of insulating parts, contacts, interrupters, response time, mechanical wear of operating mechanism, condition of oil, grids and bushings. Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various tests and inspections which are discussed later.

Filling Out Data Evaluation Sheet

4-5. Column 1 provides for space to list the condition indicators which are used for breaker evaluation. Others may be added in the future. Fill in the date the test or inspection was made in column 2. Insert any notes or remarks about the condition index in column 3. For instance, if the condition number for a condition index was low, put in the reason for it being low. Put the condition number for the particular condition indicator in column 4.

The overall breaker condition number is the lowest of the individual condition indicator numbers. This number is placed in the box in the lower right comer of the Overall Circuit Breaker Condition Data Evaluation Sheet.

Sample of this form are shown on pages 3 and 4. Information to be completed by the field is shown in script text.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Circuit Breaker Condition

Project: *Old Hydro Plant* *Unit No.* 1
Prepared by: *I.N. Spector* Date: *7/3/90*
Mfr: *GE* Model *AR-A1 (ACB)*

Item	Date of Inspection or Test	Remarks	Condition Number 0 - 100
Insulating Parts	*7/1/90*	*Insulating parts OK*	*75*
Contacts	*7/1/90*	*Minor Wear*	*75*
Interruption	*7/1/90*	*Cleaned Arc Chutes*	*75*
Response Time	*7/1/90*	*Within Spec's*	*100*
Mechanical Wear	*7/1/90*	*Minor Mechanical Wear*	*75*
		Overall Circuit Breaker Condition Index Rating	*75*

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Circuit Breaker Condition

Project: *Old Hydro Plant* *Unit No.* 1
Prepared by: *I.N. Spector* Date: *7/3/90*
Mfr: *Westinghouse* Model: *GO-3A (OCB)*

Item	Date of Inspection or Test	Remarks	Condition Number 0 - 100
Oil	*7/1/90*	*Oil Good*	*100*
Contacts	*7/1/90*	*Slight Wear*	*75*
Grids	*7/1/90*	*Grids OK*	*100*
Response Time	*7/1/90*	*Within Tolerances*	*100*
Bushings	*7/1/90*	*Slight increase in power factor*	*75*
Mechanical Wear	*7/1/90*	*Minor Wear*	*75*
		Overall Circuit Breaker Condition Index Rating	*75*

Insulating Parts

Introduction

4-6. This evaluation is used to determine the condition of the circuit breaker based upon the condition of the insulating parts. With proper maintenance the insulation of circuit breakers is designed and expected to withstand operating voltages for periods on the order of 20 to 30 years. During this time the insulation will be subject to an accumulation of deteriorating conditions which detract from its voltage withstanding capability.

Instructions for Evaluation

4-7. Condition numbers should be assigned based upon visual examination of the components, and the following considerations:

4-7. 1. Moisture, particularity when combined with dirt is the greatest deteriorating factor for insulation. Even small amounts of moisture, such as condensation, will result in electrical leakage which leads to tracking and eventual flash-over if dirt is allowed to accumulate.

4-7.2. Prolonged exposure to corona discharge will result in erosion of the surface of the insulating material. If the corrosion paths have not progressed to significant depths, surface repair can probably be accomplished.

4-7.3. Tracking is an electrical discharge phenomenon caused by electrical stress on insulation. Tracking develops in the form of streamers or sputter arcs on the surface of insulation usually adjacent to high voltage electrodes. Tracking conditions on surfaces of inorganic materials can be completely removed by cleaning the surfaces. In the case of organic materials, the surface is damaged in varying degrees depending upon the intensity of the electric discharge and the duration of the exposure. If the damage is not too severe it can be repaired by sanding and application of track resistant varnish.

4-7.4. Thermal damage caused by temperatures even slightly over the design levels for prolonged periods can significantly shorten the electrical life of insulating materials. Heat damage can be detected by:

a. discoloration
b. cracking, flaking of varnish coatings
c. embrittlement
d. delamination
e. carbonization
f. melting, oozing, or exuding of substances from within an insulating assembly

Filling Out Data Evaluation Sheet

4-8. Enter "Insulating Parts" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If there is no evidence of the above conditions, or if cleaning of the surfaces removes all traces, the rating would be 85 to 100.

Good: If the conditions exist, but only to a minor degree, but the breaker is still capable of interrupting a fault, the rating would be between 40 and 84.

Failure: If any of the conditions exist to a significant degree, the rating would be between 0 and 39.

Frequency of Inspection

4-9. The inspector should follow the recommendation of the circuit breaker manufacturer in determining how often an inspection should be made.

Contacts

Introduction

4-10. This evaluation is used to determine the condition of the circuit breaker based upon the condition of the contacts. Functioning of circuit breakers depends upon correct operation of their contacts. Air circuit breakers normally have at least two distinct sets of contacts on each pole, main and arcing. When the breaker is closed, practically the entire load current passes through the main contacts. If the resistance of these contacts becomes high, they will overheat. Increased contact resistance can be caused by pitted contact surfaces, foreign material embedded on contact surfaces, or weakened contact spring pressure. This will cause excessive current to be diverted through the arcing contacts, with subsequent overheating and burning which will shorten the life of both the contacts and the nearby insulation.

Instructions for Evaluation

4-11. Condition numbers should be assigned based upon visual inspection and the following considerations:

The contacts of oil circuit breakers are not readily accessible for routine inspection. Contact resistance should be measured. Contact engagement can be measured by measuring the travel of the lift rod. More extensive maintenance will require removal of the oil. The contacts should be inspected for erosion or pitting. Contact pressures and alignment should be checked. All bolted connections and contact springs should be inspected for looseness.

Filling Out Data Evaluation Sheet

4-12. Enter "Contacts" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If the contacts are in good condition and no other problems exist, the rating would be 85 to 100.

Good: If the contacts show only minor wear, and only minor adjustments are necessary, the rating would be 40 to 84.

Failure: If the contacts are severely damaged, or if adjustments cannot be made, the rating would be 0 to 39.

Frequency of Inspection

4-13. How often this is done will depend on the severity of the breaker duty, such as number of operations and operating current levels. Any time the breaker has interrupted a fault current at or near its maximum rating, this type of maintenance should be performed. The inspector should follow the manufacturers recommendation in determining how often a routine inspection should be made.

Interrupters

Introduction

4-14. This evaluation is used to determine the condition of an air circuit breaker based upon the condition of the interrupters. Prior to the parting of the blade arcing tip and the contact fingers, high pressure air is admitted to the arc chute. As the blade tip separates from the contacts, an arc is drawn between the blade tip and the contacts. The arc is blown downstream in the chute, splitting on the arc barrier into two sections. Each section of the arc is blown and expanded between the arc barrier and the lower arc wedge or the upper arc wedge until the interruption takes place. The product of interruption are then rapidly moved through cooler plates and up the exhaust tube.

Instructions for Evaluation

4-15. Condition numbers should be assigned based upon visual inspection. Any residue, dirt, or arc products should be removed from the interrupters. The following should be looked for:

1. Broken or cracked parts.
2. Erosion of parts
3. Dirt in interrupter (dust, loose soot, deposits from arc gases)

Filling Out Data Evaluation Sheet

4-16. Enter "Interrupters" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If the above conditions are negligible, the rating would be 9.li to 1 00
Good: If they are minor, or can be corrected, the rating would be 40 to 84.
Failure: If they exist to any great extent and cannot be corrected, the rating would be 0 to 39.

Frequency of Inspection

4-17. The inspector should follow the recommendation of the circuit breaker manufacturer in determining how often an inspection should be made.

Response Time

Introduction

4-18. This evaluation is used to determine the condition of the circuit breaker based upon its response time. In the adjustment of circuit breaker operation, the prime factors are the starting and stopping of the breaker. An analysis of breaker operation can be obtained by taking travel curves. From these curves, it can be determined whether or not the breaker has the proper speed and dashpot action. As an example, for the General Electric AR-Al air-blast circuit breaker, the essential points which are to be observed are:

1. Proper dashpot action on opening.

14. 2. Time in the arcing zone. This is determined by the K and IC measurements (see figure in manufacturer's O&M manual).

3. Proper dashpot action on closing.
4. Time before the arcing contacts part.
5. Check for two complete operations before the lock-out switches operate.

15. 6. Trip free time through breakers contacts. This can be obtained by attaching leads across one arc chute to complete the opening circuit. When the breaker is closed by the analyzer, it will trip when the blade touches the arcing contacts.

16. 7. Closing and opening curves should be as shown in the figures in the manufacturer's O&M manual.

Instructions for Evaluation

4-19. Condition numbers should be assigned based upon the following considerations:

The typical curves indicate the limits within which the actual curves should always lie. If at any time the breaker is found to operate outside these limits after proper maintenance has been performed, mechanism adjustment will be necessary in order to bring the curves back within the limits. The manufacturer will also provide a list of adjustments which should be checked to insure proper operation. An example of the manufacturers required adjustments is given below for the General Electric AR-Al air circuit breaker. Note that these may not be applicable to other air circuit-breakers.

Recommended mechanical settings:

Breaker stroke: 14-1/2" +/- 1/16"
Contact wipe: 1-7/8" +/- 1/16"
Clearance between contact blade tip and contact block: 5/16" +/- 1/16"
Variation between contact made between the three phases: 1/16"
Clearance between blast valve operator and valve stem cap: 1/16" 1/32" to 1/64"
Minimum clearance between blade and arc chute 0.002'
Lockout of pressure switch in closing circuit: 240 psi decreasing
Lockout of pressure switch in opening circuit: 225 psi decreasing
Operation of low pressure alarm switch: 250 psi decreasing
Operation of manual trip lockout: 225 psi decreasing

Acceptable values for travel curves:

Time in arcing zone: 1. 1 to 1.3 cycles

Time to arcing contacts part: 4.5 cycles

Trip free time > 8 cycles

Filling Out Data Evaluation Sheet

4-19. Enter "Response Time" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If the breaker operates within the limits specified by the manufacturer and no adjustment is required, the breaker would receive a rating of 85 to 100.

Good: If after some minor adjustment, the breaker operates within the limits, it would receive a rating of 40 to 84.

Failure: If the breaker cannot be adjusted to operate within the limits, it would receive a rating of 0 to 39.

Frequency of Inspection

4-20. For proper maintenance, it is usually necessary to take travel curves at least once a year, and compare them with curves taken the year before and with typical curves. However, the inspector should follow the recommendation of the circuit breaker manufacturer in determining how often an inspection should be made.

Mechanical Wear of Operating Mechanism

Introduction

4-21. This evaluation is used to determine the condition of the circuit breaker based upon the mechanical wear of the operating mechanism.

Instructions for Evaluation

4-22. Condition numbers should be assigned based upon visual examination of the components, and the following considerations:

The operating mechanism should be inspected for loose or broken parts; missing cotter pins or retaining keepers; missing nuts and bolts and for binding or excessive wear.

Long wearing and corrosion resistant materials are used by manufacturers and some wear can be tolerated before improper operation occurs. Excessive wear usually results in loss of travel of the breaker contacts. It can affect the operation of latches; they may stick or slip off and prematurely trip the breaker. Adjustments for wear are provided in certain parts, in others replacement is required.

Filling Out Data Evaluation Sheet

4-23. Enter "Mechanical Wear" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If there are no missing parts or evidence of wear, the breaker would receive a rating of 85 to 100.

Good: If there are any loose parts or minor signs of wear, the breaker would receive a rating of 40 to 84.

Failure: If there is excessive wear and the breaker cannot be adjusted, it would receive a rating of 0 to 39.

Frequency of Inspection

4-24. The inspector should follow the recommendation of the circuit breaker manufacturer in determining how often an inspection should be made.

Condition of Oil

Introduction

4-25. This evaluation is used to determine the condition of an oil circuit breaker based upon the condition of the oil. Oil, in addition to providing insulation, also acts as an arc extinguishing medium. In this process it absorbs arc products and experiences some decomposition in the process. The principle contaminants are moisture, carbon, and sludge. The sludge settles on the horizontal parts and at the bottom of the tank. It interferes with the normal circulation of the oil; and thus its ability to dissipate heat. However moisture is the most dangerous contaminant of insulating liquids. As small an amount as ten parts per million can reduce the dielectric strength of insulating oil below its minimum acceptable level.

Instructions for Evaluation

4-26. Condition numbers should be assigned based upon the following considerations:

A dielectric breakdown test is a positive method of determining the insulating value of the oil. This test measures the ability of an insulating liquid to withstand electrical stress up to the point of failure. The minimum acceptable breakdown values are 22 kV for mineral oil and 25 kV for askarel.

The acidity of the oil is a measure of how much it has oxidized (and thus deteriorated) and how great is the tendency to form sludge. Acidity is measured by a neutralization number as covered in ASTM D-1534. A maximum permissible neutralization number for oil is 0.4.

The oil can also be visually inspected. New oil is clear, while a dark oil indicates sludge or other contamination.

Filling Out Data Evaluation Sheet

4-27. Enter "Oil" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If the oil is new, or has been re-refined, and passes all the tests, it would receive a rating of 85 to 100.

Good: If the oil is not new, but still passes the all the above tests, it would be rated 40 to 84.

Failure: If the oil fails any of the tests, it would receive a rating of 0 to 39.

Frequency of Inspection

4-28. The inspector should follow the recommendation of the circuit breaker manufacturer in determining how often an inspection should be made.

Grids

Introduction

4-29. This evaluation is used to determine the condition of an oil circuit breaker based upon the condition of its grids. '"Grids" is a term used to describe the assemblies on the interrupters of oil circuit breakers, made of stacked flat shapes fabricated mostly of vulcanized fiber. Their function is to direct the arc and the arc-produced flow of oil which helps to quench the are. Vulcanized fiber absorbs moisture and this causes uneven swelling and shrinking as the moisture is absorbed and released over time. Since the grids are immersed in oil, the only moisture is that which is in the oil. Therefore the problem is usually slight, but the occasional extreme case can make circuit breaker overhauls difficult by interfering with alignment. This is also suspected of interfering at times with proper circuit breaker operation. Moisture absorption also increases the grids power factor. Normally this is not a problem (unless it is extreme), but a change in grid power factor can mask changes elsewhere. Thus it is desirable to keep the power factor as low as possible. Maintaining the oil quality as high as possible would assist in this endeavor. Carbon accumulation over many years can permanently increase power factor if the carbon becomes absorbed into the fiber.

Instructions for Evaluation

4-30. Condition numbers should be assigned based upon visual inspection of the components. Surface carbon should be removed by cleaning.

Filling Out Data Evaluation Sheet

4-31. Enter "Grids" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If a grid appears to be in good condition, and does not interfere with alignment, it would be rated 85 to 100.

Good: If the grid shows evidence of carbon accumulation, but alignment is within specifications and the carbon is removed by cleaning, the rating would be 40 to 84.

Failure: If the grid interferes with proper breaker operation, the rating would be 0 to 39.

Frequency of Inspection

4-32. The grids should be disassembled as seldom as possible, but after several years it may be needed. The inspector should follow the recommendation of the circuit breaker manufacturer in determining how often an inspection should be made.

Bushings

Introduction

4-33. This evaluation is used to determine the condition of the circuit breaker based upon the condition of the bushings.

Instructions for Evaluation

4-34. Condition numbers should be assigned based upon visual examination of the bushings, and the following considerations:

The bushings should be cleaned and dried. A power factor test should be performed on each line-side and load-side bushing assembly complete with stationary contacts and interrupters, with the circuit breaker open. A power factor test should also be performed on each part of the circuit breaker with the breaker closed. In addition, tests should be made of each bushing. Data evaluation should be based on industry standards, correlation of data obtained with test data from similar units, and comparison with previous test data on the same equipment. The bushings should also be inspected for damage to the ceramic material, leakage, and condition of gaskets.

Filling Out Data Evaluation Form

4-35. Enter "Bushings" in the first column. Fill in the date on which the inspection was made in the second column. Make any comments or notes on the condition of parts inspected in the third column. Finally, in the fourth column, enter the condition number based on the following criteria:

Excellent: If the bushings are in good condition, with no 'damage or leakage, and the power factor is consistent with industry standards and hasn't appreciably changed, the rating would be 85 to 100.

Good: If the power factor has changed, but is still within industry standards, the rating would be 40 to 84.

Failure: If the power factor has changed appreciably and is no longer within industry standards, or if there is leakage or damage to the bushings, the rating would be 0 to 39.

Frequency of Inspection

4-36. The inspector should follow the recommendation of the circuit breaker manufacturer in determining how often an inspection should be made.

EX-1-FRM.PM4 PAGE 1 OF 1

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Circuit Breaker Condition

Project: _____ *Unit No.*_____

Prepared by: _____ Date:_____

Mfr: _____ Model: _____

Item	Date of Inspection or Test	Remarks	Condition Number 0 - 100
		Overall Excitation System Condition Index Rating	

PART VIII: THRUST BEARINGS

Program, Format and Method

Explanation of Program

8-1. The overall thrust bearing condition number is a number between 0 and 100 which will be used to define the present condition of a generator thrust bearing. The number will be used in the REMR Condition Index Scale which is shown below.

The overall thrust bearing condition number is calculated from three condition index numbers. These three condition numbers are determined from various inspections done on a generator thrust bearing runner and shoes.

Condition Index Scale

Value	Condition Description	
85-100	Excellent	No noticeable defects. Some aging or wear may be noticeable.
70-84	Very Good	Only minor deterioration or defects are evident.
55-69	Good	Some deterioration or defects are evident, but function is not significantly affected.
40-54	Fair	Moderate deterioration. Function is still adequate.
25.-39	Poor	Serious deterioration in at least some portions of equipment. Function is inadequate.
10-24	Very Poor	Extensive deterioration. Barely functional.
0-9	Failed	No longer functions. General failure or failure of a major component.

Figure D-1

The three condition indices selected are: runner visual condition, shoe visual condition, and oil condition. The inspections can be performed by project personnel.

Details of the generator thrust bearing and shoe inspection are available in the Generator Rewind Guide Specification (CW-16211 FEB92), Paragraph 3.9 Generator Thrust Bearing Field Inspection.

Explanation of Format

8-2. The condition indices all have a similar format. The first sheet IS an explanation sheet which describes the test or inspection, gives instructions on doing the test or inspection, explains how to fill out the data-evaluation sheet and gives the recommended frequency of doing the test or inspection. Next, there are tables which are used to determine a condition number based on the results of measurements and inspections. Following this is the data-evaluation sheet where information is recorded and calculations made. Also attached is a sample data-evaluation sheet. The last sheets are specific inspection sheet for recording measurement results and damage.

Explanation of Method

8-3. A condition number between O and 100 is determined for each condition index based on the results of inspections. Each explanation sheet gives instructions on testing and evaluation. The overall condition number for the thrust bearing is the lowest of the three condition index values.

Overall Thrust Bearing Condition

Introduction

8-4. The overall thrust bearing condition is calculated using three condition indicators: visual inspection of runner, visual inspection of shoes and oil condition. Each indicator is assigned a condition number. The condition numbers are calculated based on the results of various inspections which are discussed later.

Filling out Data Evaluation Sheet

8-5. Column 1 lists the three condition indicators which are used for evaluation. Others may be added in the future. Fill in the date the inspection was made in column 2. Put any' notes or remarks about the condition index in column 3. For instance, if the condition number for a condition index was low, put in the reason for it being low. Put the condition number for a particular condition index in column 4. This number is obtained from the box in the lower right comer of the data evaluation sheet for each individual indicator. The value used for shoe inspections should be the lowest value obtained for any individual shoe. The overall thrust bearing condition number is the lowest condition number of the three indicators. This number is placed in the box in the lower right comer of the data evaluation sheet. A .sample-of the overall thrust bearing condition data evaluation sheet is shown on page 4. Information that would be completed by the field is shown in script text.

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Thrust Bearing Condition

Project: *Old Hydro Plant* *Unit No. 1*
Prepared by: *I.N. Spector* Date: *7/3/90*
Type of Bearing: *G.E. Spring Type*

Item	Date of Inspection or Test	Remarks	Condition Number 0 - 100
Visual Inspection of Runner	*7*/3/90	*Gap in joint*	*30*
Visual Inspection of Shoes	*7/3/90*	*Shoe #9 has loss of babbitt near leading edge*	*30*
Oil Condition	*7/3/90*	*Increasing Lead Content*	*50*
Overall Thrust Bearing Condition Index Rating			*30*

Thrust Bearing Runner - Visual Inspection

Introduction

8-6. This inspection is used to determine the condition of the generator thrust bearing based on a visual inspection of the runner. A condition number will be assigned to the runner based on the visual condition.

Instructions for Evaluation

8-7. Care should be taken not to damage the bottom surface of the thrust runner during inspection. Written and mapped descriptions of scratches, damage or defects shall be made. The information shall be recorded on inspection sheets TB-I-FRM.PM4, PAGES 3- 6.

On the data-evaluation sheet, a summary of the inspection is recorded. The next paragraph explains in detail how to fill out the data-evaluation sheet.

Filling Out Data Evaluation Sheet

8-8. Fill out the name of the area inspected, e.g. runner bottom surface, runner half joint etc. in column 1. Indicate the date the inspection was made in column 2. Put in a summary of what damage, if any, was found on that area or component in column 3.

A condition number between 0 and 100 will be assigned to the runner surfaces and p~ depending on the damage and defect5 which were found visually. These condition numbers are obtained from Table 1 and placed in column 4.

The overall runner visual condition number is the lowest number from column 4.This number is placed in the box in the lower right corner of the data-evaluation sheet.

Frequency of Inspection

8-9. This inspection does not require the removal of the generator rotor. I t does require jacking the rotor and removal of at least two of the thrust bearing segments {shoes). One of the segments that is removed should be in a location that will allow inspection of the runner radial joint. This inspection should be performed in conjunction with the shoe inspection. Since this inspection requires a partial disassembly, it should be performed infrequently. Recommended inspections are during extended maintenance periods, unit overhaul or when a problem is suspected.

Table 8-1
Condition Numbers for Thrust Bearing Runner - Visual Inspection

Running Face of Runner

	Condition
No visible scratches or defects	100
Minor scratches and no defects	70
Moderate scratches or minor defects	50
Large scratches or moderate defects	30
Major defects or damage	0

Running Halves' Joint

Gap of Joint	Condition
<.001	100
<.0015	70
<.002	50
>.002	30

Running Bolts

Percent of Specification Tightness	Condition
100	100
80	60
60	30

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Visual Inspection of Thrust Bearing Runner

Project: *Old Hydro Plant* *Unit No.* 1
Prepared by: *I.N. Spector* Date: *7/3/90*
Type of Bearing: *G.E. Spring Type*

Item	Date of Inspection or Test	Remarks	Condition Number 0 - 100
Running Face	7/3/90	*Surface in excellent condition*	*100*
Gap at joint	*7/3/90*	*Feeler gage indicates 0.021 at outer 1/3 of joint*	*30*
Runner Bolts	*7/3/90*	*Torque on all bolts on outer parts of joint at 60% torque*	*60*
		Thrust Bearing Runner Visual Condition Index Rating	*30*

REMR Hydropower Condition Indicator Program

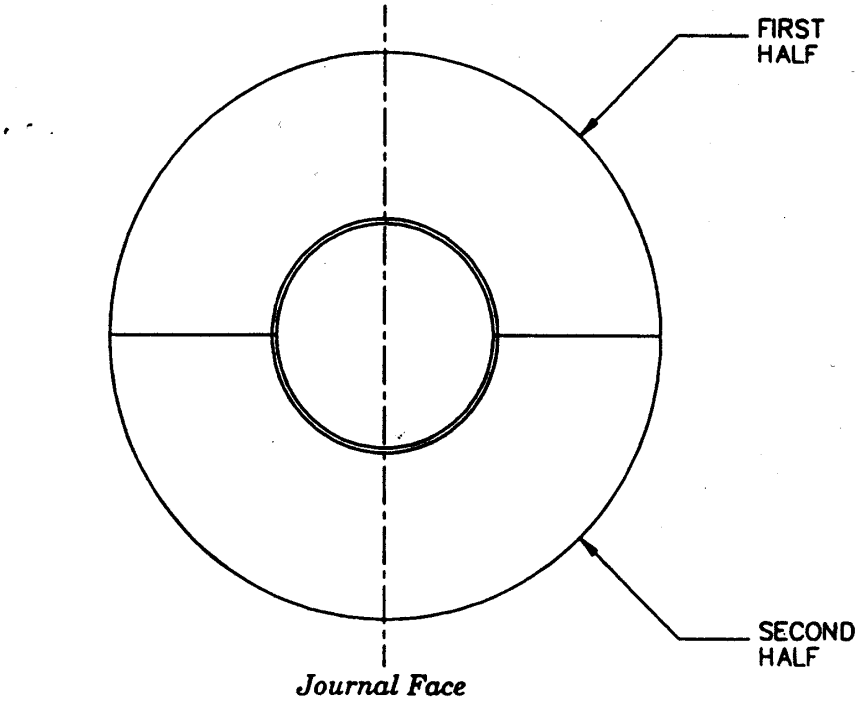
Thrust Bearing Runner Inspection Sheet
Sheet 1 of 2

Project: _____ Unit No._____

Prepared by:_____ Date: _____

Type of Bearing:_____

Visually inspect runner. Check for any scratches, gouges, tears, etc. on surfaces and at horizontal joint. Record condition of holes, threads and any other items necessary. Record approximate location of damage and map location. List any items requiring replacement.



REMR Hydropower Condition Indicator Program

Thrust Bearing Runner Inspection Sheet
Sheet 2 of 2

Project: _____ Unit No._____

Prepared by:_____ Date: _____

Type of Bearing:_____

Record of Missing Hardware:

Check for nay missing or loose bolts or other hardware and record.

If none, state none.

_____

_____

_____

_____

_____

_____

_____

_____

_____

_____

_____

Thrust Bearing Shoes - Visual Inspection

Introduction

8-10. This inspection is used to determine the condition of the genera tor thrust bearing based on a visual inspection of the shoes. A complete description of this inspection can be found in the thrust bearing field inspection portion (paragraph 3.9) of the Generator Rewind Guide Specification.

A condition number is assigned to each shoe based on the visual condition.

Instructions for Evaluation

8-11. At least two bearing shoes should be removed from the generator following the manufacturer's removal instructions. Care should be taken not to damage component surfaces. At least one of the thrust bearing shoes to be removed must allow access for inspection of one side of the runner radial split. If only two shoes are removed, the second shoe should be between 90 and 180-.d-egrees apart from the first shoe. The babbitt surface of each shoe that is removes should be visually inspected and areas of damage or defects mapped and recorded on the inspection sheet. A summary of the inspection is recorded on the data evaluation sheet.

Filling Out Data Evaluation Sheet

8-12. In column 1 fill in the shoe number. Each shoe removed should be given a number and should be recorded on a separate line. In column 2, indicate the date the inspection was made. In column 3 put in a summary of what damage, if any, was found on that shoe.

A condition number between 0 and 100 is assigned to each shoe depending on the damage and defects which were visually seen. These condition numbers are obtained from Table 2, and placed in column 4.

The overall shoe visual condition number is the lowest number for any of the shoes. This number is place din the box in the lower right corner of the data-evaluation sheet.

Frequency of Inspection

8-13. Since this inspection requires a partial disassembly, it should be performed infrequently. Recommended inspections are during extended maintenance periods, unit overhaul or when a problem is suspected.

Table 8-2
Stationery Segments (Shoes)

Babbitt Surface	Condition Number
No visible scratches or defects	100
Minor scratches and no defects	70
Moderate scratches or minor defects	50
Large scratches or moderate defects	30
Major damage other than scratches	10

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Visual Inspection of Thrust Bearing Runner

Project: *Old Hydro Plant* *Unit No.* 1
Prepared by: *I.N. Spector* Date: *7/3/90*
Type of Bearing: *G.E. Spring Type*

Item	Date of Inspection or Test	Remarks	Condition Number 0 - 100
Per *1*	*7*/3/90	*Minor scratches*	*70*
2	*7/3/90*	*Minor scratches*	*70*
3	*7/3/90*	*Minor scratches*	*70*
4	*7*/3/90	*1" Defect (1" dia) near trailing edge*	*70*
5	*7/3/90*	*Minor scratches*	*70*
6	*7/3/90*	*Minor scratches*	*70*
7	*7*/3/90	*Minor scratches*	*70*
8	*7/3/90*	*Minor scratches*	*70*
9	*7/3/90*	*2"dia loss of babbitt near leading edge*	*70*
10	*7*/3/90	*Minor scratches*	*70*
11	*7/3/90*	*Minor scratches*	*70*
12	*7/3/90*	*Minor scratches*	*70*
Thrust Bearing Shoe Visual Condition Index Rating			*30*

REMR Hydropower Condition Indicator Program

Thrust Bearing Shoe Inspection Sheet

Shoe Number _____

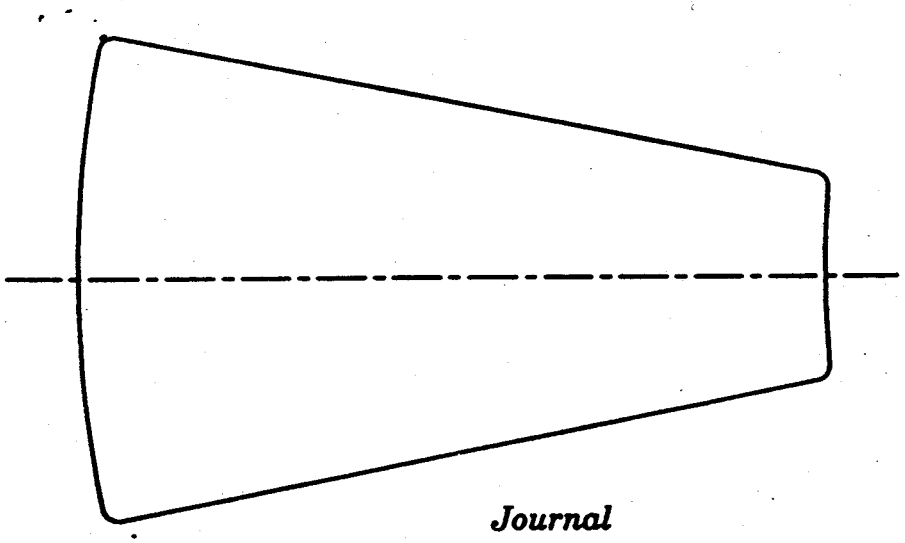
Project: _____ Unit No._____

Prepared by:_____ Date: _____

Type of Bearing:_____

Clean and identify shoe segments. Record visual condition of each segment. Check for bruises, gouges, scratches, etc. Indicate areas of damage on drawing below. Make one sheet for each shoe segment.

Segment No. _____



Journal
(Babbit) Side

Oil Condition

Introduction

8-14. This indicator is used to gauge the condition of the thrust bearing, not the condition of the thrust bearing oil. Spectrographic analysis can give insight into the current condition of thrust bearing components and is a strong indicator of whether the thrust bearing system is wearing out prematurely. Iron in the oil indicates steel corrosion. Lead or tin in the oil indicates babbitt loss. Water in the oil indicates cooling system contamination.

Instructions for Evaluation

8-15. To obtain the condition numbers, oil samples must be drawn from the system and sent to a qualified laboratory for spectrographic emissions testing. The sampling procedure should be as follows:

1) Obtain sampling containers from a testing laboratory .Only one sample will be required but multiple samples from different locations will increase the confidence level in the test result. Using improperly cleaned containers will guarantee inaccurate results.

2) Choose convenient sampling locations.

3) Take samples during operation or immediately following shutdown.

4) Send samples to testing laboratory and request a full spectrographic emissions analysis.

5) Determine the condition number for the oil using Table 8-4 and the laboratory test data.

Filling Out Data-Evaluation Sheet

8-16. Fill out the Data Evaluation Sheet only for the most contaminated of the oil samples tested. Column l list the four substances to be evaluated. Obtain the original, manufacturer analysis of the oil being tested. Record in column 2 the manufacturer's measurement of the content of each substance in parts per million present at oil purchase. In column 3, list the laboratory test results in parts per million for the substances evaluated. List the increase in contaminant content in parts per million in column 4. You may wish to record suspected reasons for a contaminant increase or make remarks regarding sampling locations, etc. in column 5. The condition number for each substance is obtained from Table 8-4 and placed in column 6. After condition numbers have been assigned to each tested substance, choose the lowest of the condition numbers and place it in the box in the lower right-hand column of the Data Evaluation Sheet labeled Overall Thrust Bearing Oil Condition Index. A sample of this form is shown on page 8-18. Information to be completed by the field is shown in script text.

Frequency of Inspection

8-17. This testing should be performed annually.

Table 8-4

Increase (ppm)	Condition Number
0	100
0 - 1	90
1 - 5	80
5 - 10	70
10 - 20	60
20 - 50	50
50 - 100	40
100 - 250	30
250 - 500	20
>500	10

Where INCREASE = PRESENT CONTAMINANT CONTENT (ppm) - ORIGINAL CONTAMINANT CONTENT (ppm)

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Overall Thrust Bearing Condition

Unit No._____
Project: _____
Prepared by: _____ Date:_____
Type of Bearing _____

Item	Date of Inspection	Remarks	Condition Number 0 - 100
Visual Inspection of Runner			
Visual Inspection of Shoes			
Oil Condition			
		Overall Thrust Bearing Condition Index Rating	

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Visual Inspection of Thrust Bearing Condition

Unit No. *1*

Project: *Old Hydro Project*

Prepared by: *I.N. Spector* Date: *7/3/90*

Type of Bearing *G.E. Spring Type*

Item	Date of Inspection	Remarks	Condition Number 0 - 100
		Thrust Bearing Runner Visual Condition Index Rating	

REMR Hydropower Condition Indicator Program

Thrust Bearing Runner Inspection Sheet
Sheet 1 of 2

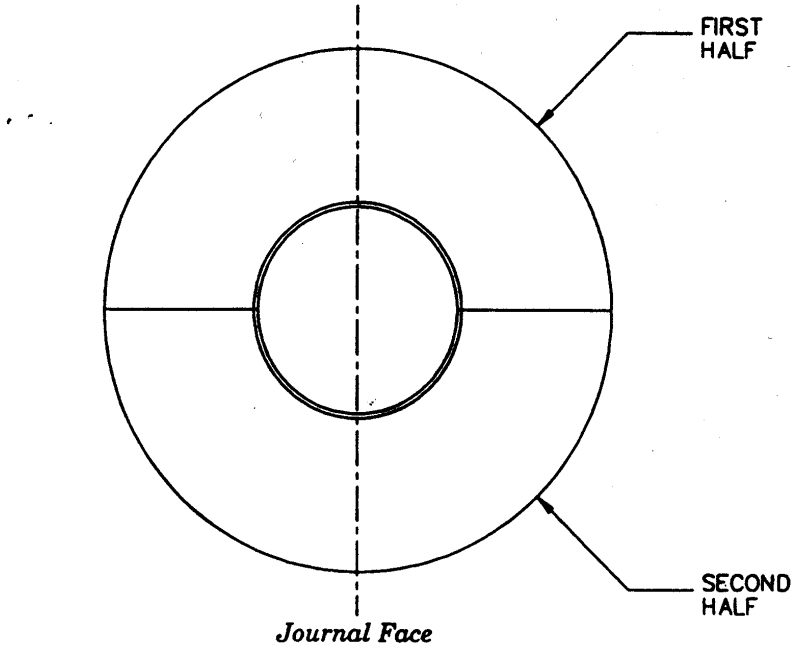
Unit No._____

Project: _____

Prepared by: _____ Date:_____

Type of Bearing _____

Visually inspect runner. Check for any scratches, gouges, tears, etc. on surfaces and at horizontal joint. Record condition of holes, threads and nay other items necessary. Record approximate location of damage and map location. List any items requiring replacement.



REMR Hydropower Condition Indicator Program

Thrust Bearing Runner Inspection Sheet
Sheet2 of 2

Project: _____ Unit No._____

Prepared by:_____ Date: _____

Type of Bearing:_____

Record of Missing Hardware:

Check for nay missing or loose bolts or other hardware and record.

If none, state none.

_____

_____

_____

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_____

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_____

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_____

_____

REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Visual Inspection of Thrust Bearing Condition

Unit No._____
Project: _____
Prepared by: _____ Date:_____
Type of Bearing _____

Shoe Number	Date of Inspection	Remarks	Condition Number 0 - 100
	Thrust Bearing Shoe Condition Index Rating		

REMR Hydropower Condition Indicator Program

Thrust Bearing Shoe Inspection Sheet

Shoe Number _____

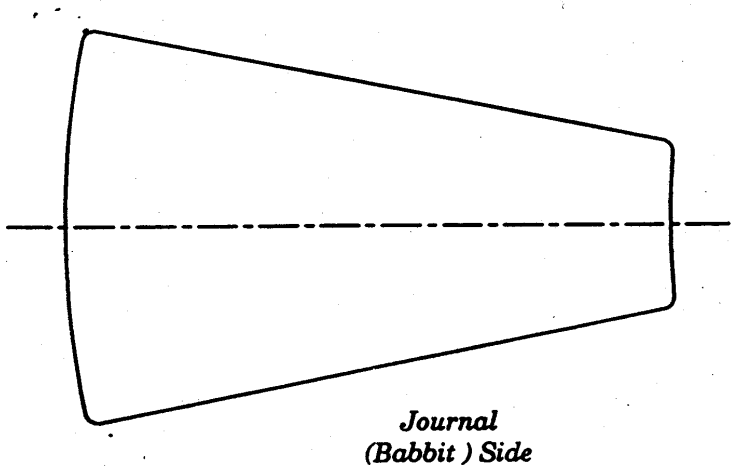
Project: _____ Unit No._____

Prepared by:_____ Date: _____

Type of Bearing:_____

Clean and identify shoe segments. Record visual condition of each segment. Check for bruises, gouges, scratches, etc. Indicate areas of damage on drawing below. Make one sheet for each shoe segment.

Segment No. _____



REMR Hydropower Condition Indicator Program

Data Evaluation Sheet
Thrust Bearing Oil Condition

Unit No._____
Project: _____
Prepared by: _____ Date:_____
Type of Bearing _____

Contaminant	Original Content (ppm)	Present Content (ppm)	Increase in Content (ppm)	Remarks	Condition Number 0 - 100
Iron					
Lead					
Tin					
Water					

Thrust Bearing Oil Condition Index Rating

Targets:

Hydropower Operations & Asset Management
Plant Maintenance & Life Management

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